STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL"), AN INDIANA CORPORATION, FOR APPROVAL OF CLEAN ENERGY PROJECTS AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR CONSTRUCTION AND USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECTS THROUGH IPL'S ENVIRONMENTAL COMPLIANCE COST RECOVERY ADJUSTMENT("ECCRA"); FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; FOR THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, AND OPERATION AND MAINTENANCE COSTS, UNTIL SUCH COSTS ARE REFLECTED FOR RATEMAKING PURPOSES, ALL PURSUANT TO IND. CODE §§ 8-1-2-6.1, 8-1-2-6.7, 8-1-2-6.8, 8-1-2-42(a), 8-1-8.4, 8-1-8.7, 8-1-8.8 AND 170 IAC 4-6-1 ET SEQ.	)	**CAUSE NO. 44242**

SUBMISSION OF REDACTED TESTIMONY AND EXHIBITS OF JEREMY I. FISHER, PhD, and PETER J. LANZALOTTA

Citizens Action Coalition of Indiana and Sierra Club (collectively "Joint Intervenors"), by counsel, respectfully submit the redacted testimony and exhibits of Jeremy I. Fisher, PhD, and Peter J. Lanzalotta in the above referenced Cause to the Indiana Utility Regulatory Commission.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 28th day of January, 2013, to the following:

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EXHIBIT A

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL"), AN INDIANA CORPORATION, FOR APPROVAL OF CLEAN ENERGY PROJECTS AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR CONSTRUCTION AND USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECTS THROUGH IPL'S ENVIRONMENTAL COMPLIANCE COST RECOVERY ADJUSTMENT("ECCRA"); FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; FOR THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, AND OPERATION AND MAINTENANCE COSTS, UNTIL SUCH COSTS ARE REFLECTED FOR RATEMAKING PURPOSES, ALL PURSUANT TO IND. CODE §§ 8-1-2-6.1, 8-1-2-6.7, 8-1-2-6.8, 8-1-2-42(a), 8-1-8.4, 8-1-8.7, 8-1-8.8 AND 170 IAC 4-6-1 ET SEQ.	)	**CAUSE NO. 44242**

Direct Testimony of
Jeremy I. Fisher, PhD

REDACTED VERSION

On Behalf of
Citizens Action Coalition and Sierra Club

January 28, 2013

Table of Contents

Table of Figures

Table of Tables

1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy Fisher. I am a scientist with Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q Please summarize your work experience and educational background.

A I have ten years of applied experience as a geological scientist, and five years of working within the energy planning sector, including work on integrated resource plans, long-term planning for utilities, states and municipalities, electrical system dispatch, emissions modeling, the economics of regulatory compliance, and evaluating social and environmental externalities. I have provided consulting services for various clients, including the U.S. Environmental Protection Agency (EPA), the National Association of Regulatory Utility Commissioners (NARUC), the California Energy Commission (CEC), the California Division of Ratepayer Advocates (CA DRA), the National Association of State Utility Consumer Advocates (NASUCA), National Rural Electric Cooperative Association (NRECA), the state of Utah Energy Office, the state of Alaska, the state of Arkansas, the Regulatory Assistance Project (RAP), the Western Grid Group, the Union of Concerned Scientists (UCS), Sierra Club, Earthjustice, Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), Stockholm Environment Institute (SEI), Civil Society Institute, and Clean Wisconsin.

I have provided testimony in electricity planning and general rate case dockets in Wyoming, Utah, Kansas, Kentucky, Oregon, and Wisconsin.

Prior to joining Synapse, I held a post doctorate research position at the University of New Hampshire and Tulane University examining the impacts of Hurricane Katrina.

I hold a B.S. in Geology and a B.S. in Geography from the University of Maryland, and a Sc.M. and Ph.D. in Geological Sciences from Brown University.

My full curriculum vitae is attached as Exhibit JIF-1.

Q **On whose behalf are you testifying in this case?**

A I am testifying on behalf of Citizens Action Coalition and Sierra Club.

Q **Have you testified in front of the Indiana Utility Regulatory Commission previously?**

A No, I have not.

Q **What is the purpose of your testimony?**

A My testimony evaluates the reasonableness of Indianapolis Power and Light's (IPL or the Company) application for the issuance of a certificate of public convenience and necessity (CPCN) for construction and use of environmental equipment at five coal-fired power plant units, namely Petersburg Units 1 through 4 and Harding Street Unit 7, or the "Big Five" as named by the Company. Specifically, I evaluate the testimony and workpapers of Mr. James Ayers, critique the methodology employed by the Company to justify these new investments, and propose an alternate economic evaluation methodology to determine the economic outcome of the Big Five.

Q How much is the Company proposing to invest as part of this application?

A To comply with the recently promulgated federal Mercury and Air Toxics Standard (MATS), the Company anticipates spending about **$511 million**[1] (before allowance for funds used during construction, AFUDC) to install new baghouses and upgrade existing electrostatic precipitators (ESP), upgrade existing flue gas desulfurization (FGD), and implement dry sorbent injection (DSI) and activated carbon injection (ACI) systems.[2]

In addition, the Company anticipates spending between **$[redacted] and $480 million**[3] in the near future to comply with other upcoming federal regulations, including proposed National Ambient Air Quality Standards (NAAQS) for oxides of nitrogen (NOx) and particulate matter (PM), the proposed Coal Combustion Residuals (CCR) rule requiring the mitigation of existing coal ash impoundments and new coal waste handling techniques, the emerging Effluent Guidelines under the National Pollutant Discharge Elimination System (NPDES) permit program governing the disposal of wastewaters into surface waterways, and the proposed Water Intake Structures rule (known as provision 316(b)). The Company is not seeking recovery of these costs in this application, but it did include $[redacted] million as incremental costs in its economic evaluation.

Q What are your findings regarding the Company's application?

A The Company's application is deficient regarding the economic justification for the controls requested in this CPCN. The economic evaluation methodology presented by Company witness Ayers is insufficient, structurally flawed, inconsistent with the application and materials provided in discovery, contains numerous errors, does not explore the full range of resource options available to the Company, does not adequately test the sensitivity of its proposed strategy for uncertainties in key assumptions, and, generally, does not comport with

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[1] IPL Witness Cutshaw, Supplemental Direct Testimony, p3 line 8.
[2] IPL Witness Moore, Direct Testimony, p5 lines 4-8. Also Petitioner's Exhibit SC-3, p3 Table 1.
[3] *See* sum of Petitioner's Exhibit JMA-2, column "CAPEX" ($480 million) and workpapers of witness Ayers, tab "OTHER ENVIRO + TOTAL", cell T15 ($[redacted] million).

reasonable planning practice. The Commission should reject Mr. Ayers' analysis and conclusions in full.

Q Did you provide an alternative economic evaluation methodology to that provided by Mr. Ayers?

A Yes. To create a reasonable and auditable framework for analysis, I created a cash flow model using the Company's assumptions and inputs, when available and feasible, and using public information otherwise. I will describe my model and inputs later in this testimony.

Q What are the results of your analysis?

A Using the mid-range gas price that IPL obtained from Ventyx,[4] a mid-range carbon dioxide (CO_2) price forecast,[5] and other cost-based assumptions provided by IPL,[6] I find that retrofit of each of the Big Five units is non-economic relative to a new combined cycle gas turbine (CCGT) replacement unit. Individually, each unit is non-economic by anywhere from $17 to $158 million (2012$) on a present value basis (see Table 1, below). Collectively, I estimate that ratepayers would pay an additional $373 million between 2015 and 2040 if IPL retrofits this fleet of units relative to replacing them with similarly-sized CCGTs.

Table 1. Benefit of Coal Unit Retirement with mid-gas and Synapse mid CO_2 price.

	Petersburg 1	Petersburg 2	Petersburg 3	Petersburg 4	Harding Street 7	Big Five Units
PVRR Coal Unit (M 2012$)	$1,540	$2,123	$3,198	$2,086	$2,652	$11,599
PVRR Gas Replacement (M 2012$)	$1,459	$1,965	$3,181	$2,026	$2,596	$11,226
Benefit of Retirement (M 2012$)	**$81**	**$158**	**$17**	**$60**	**$57**	**$373**

[4] The same as provided to the Company by Ventyx from the Spring 2012 case, and referenced in Mr. Ayers analysis.
[5] The Synapse 2012 Mid forecast, discussed in more depth later in this testimony.
[6] Cost-based assumptions include capital costs, depreciation expenses, fixed and variable operations and maintenance costs, coal prices, and financial assumptions such as inflation rate, discount rate, book life, and gross revenue conversion factor.

Benefit of Retirement (2012 $/kW)	*$352*	*$365*	*$32*	*$112*	*$134*	*$172*

Petersburg 1, 2, and 4 are either non-economic or marginal even at low CO_2 prices. I discuss the range of results and implications later in this testimony.

Q What are your recommendations to the Commission regarding the Company's application for CPCN at Petersburg Units 1 – 4 and Harding Street Unit 7?

A Based on my review of Mr. Ayers' workpapers and analysis, and my own reconstruction of the Company's analysis, I recommend that the Commission deny CPCN for Petersburg Units 1, 2, and 4 unconditionally.

Further, I recommend that the Commission order the Company to re-file the application for CPCN on Petersburg Unit 3 and Harding Street Unit 7 at such time that the Company is able to produce a reasonable and transparent economic analysis of the costs and benefits of retrofitting these units, with adequate alternatives and sensitivities explored and explained.

2. Overview of the Company's Economic Analysis

Q Please describe the economic evaluation methodology used by the Company to justify the equipment contemplated in this CPCN.

A Mr. Ayers presents an analysis designed to test the economic viability of retrofitting all of the Petersburg units by testing the cost of implementing the retrofits against replacing the plant with a single CCGT. Individual units were not analyzed; rather the analysis reviews the proposition that the entire plant is either retrofitted or retired as a single bundle. The results of this analysis were scaled to the Harding Street Unit7.

The analysis considers three basic input variables – incremental capital costs, incremental fixed and variable operation and maintenance (O&M) expenses – and a 'penalty' for operating a CCGT rather than a coal unit. At its core Mr. Ayers' analysis translates the capital cost of the retrofits into a dollar per kilowatt ($/kW) basis, adds in the cost of operations and maintenance (O&M)[7] on a $/kW basis, and compares that total cost to the capital cost of a replacement gas unit with O&M expenses (also on a $/kW basis).

Key to the analysis is a single value called the "CCGT 'Penalty.'"[8] This value represents the Company's estimate of the difference between the variable production cost of dispatching a coal plant and dispatching a gas plant. It also includes an adjustment for the annual quantity of electricity the Company would purchase from the market (to the extent that the gas capacity is dispatched in fewer hours than the coal capacity). The dispatch spread is measured in $/MWh, and translated into $/kW.

Table 2, below, shows the basic variables that go into the Company's analysis.

Table 2. Elements of Ayers Economic Analysis

Variable	Existing Coal Plant	CCGT Replacement
Capital Cost	Capital Cost of Retrofits	Capital Cost of CCGT
O&M Expenses	O&M of Existing Coal + O&M of Retrofits	O&M of new CCGT
CCGT 'Penalty' of Gas Operation		Difference between projected coal and gas variable cost in 2016, with market purchase adjustment

The Company derives a "breakeven" capital cost for the retrofits – i.e. the level of cost that the retrofits would have to reach in order to tip the balance towards the CCGT replacement unit. It is also expressed in $/kW. As long as the Company's

[7] It is not clear if the cost of O&M includes variable O&M expenditures or ongoing capital expenses. Ayers workpaper tab "O&M + Fixed 10-year" states "Projected Capital + O&M (above) includes operating maintenance capital and expense and existing environmental O&M costs…" However, the annual number cited for 2012 for all of Petersburg ([redacted]) is less than the total "base" fixed O&M by unit provided by the Company in CAC-SC DR 1-48 Supplemental ([redacted]), is approximately the same order of magnitude as total non-fuel expenses listed in FERC Form 1 for Petersburg in 2011 ($95,559,595), and is far smaller than the combination of fixed and variable O&M plus capital expenditures in 2011 ($257,444,278). Therefore, it is likely that the value for "Petersburg Total - Projected Capital + O&M" excludes both annual capital expenses and variable O&M costs.

[8] Also called the "CERA dispatch spreads" in Ayers Direct, p10 line 7 and "IPL's Big Five Dispatch Advantage" in Ayers Direct, p10 lines 17-18.

estimate of the cost of the retrofits is sufficiently less than this breakeven cost, the Company expresses confidence that the retrofits are economic.

Q Why is the CCGT 'Penalty' so key to this analysis?

A The CCGT 'Penalty' is an important variable. It represents all of the production costs, performance metrics, and fuel prices associated with both gas and coal. This factor represents over one third of the total present value revenue requirement (PVRR) of building the CCGT, according to the Company's analysis.[9] The CCGT 'Penalty' consolidates numerous separate factors, many of which change over time, into a single value, including:

- the annual cost of coal;
- the heat rate of the coal unit;
- the variable O&M of the coal unit;
- the capacity factor of the coal unit;
- the cost of natural gas;
- the heat rate of the CCGT replacement;
- the variable O&M of the CCGT replacement;
- the capacity factor of the CCGT replacement;
- the price of market energy in hours in which the coal unit operates and the gas unit does not, or vice versa.

Q What are the Company's assumptions regarding the CCGT 'Penalty' value?

A The Company makes several assumptions to derive this value.

- o First, it assumes the spread is based on a generic coal unit and a generic gas unit in a future year, rather than on the specifications of the Company's coal units, post-retrofit;
- o Second, it assumes the coal unit will always dispatch at an 80% capacity factor while the gas unit will <u>always</u> dispatch at a 50% capacity factor;

[9] Total PVRR (2015-2040) of CCGT = $[redacted]/kW; PVRR of 'Penalty' = $[redacted]/kW.

- Third, it assumes the annual cost of market energy is exactly the average price of the generic gas and coal unit;[10]
- Fourth, it determines that the assumptions utilized by the consulting group CERA for coal and gas operations are fully consistent with the actual operations of IPLs coal and gas units;
- Finally, the Company assumes that a generic CCGT would penalized by$[redacted]/MWh in 2015$, or $[redacted]/MWh in 2012$ relatively to a generic coal unit, and that such penalty would grow at 1.45% (in real terms), an assumption which is mathematically incorrect. I discuss this significant error later.

Q Why does the Company perform the analysis using the three simplified variables shown in Table 2?

A The Company appears to be expressing the entire analysis in $/kW basis to eliminate the need to scale a gas plant to the size of the coal plant under consideration. Mr. Ayers states that the Company "us[es] a spreadsheet evaluation for both simplicity and transparency."[11] While I agree that this analysis is simple, it is by no means transparent. In fact, the assumptions underlying many of the Company's values, including ongoing capital and O&M expenditures, capital and O&M costs for "Other" environmental equipment, and of course, dispatch and market purchases, are so thoroughly obscured that no party could audit and verify the Company's findings.

Q Does the Company's economic analysis account for changes to its loads and resources over time?

A No. By simply comparing the economics of the Petersburg Units and Harding Street 7 with a single CCGT, the Company essentially ignores changes to the loads and resources on its system that could have significant bearing on the

[10] For example, if the generic coal unit has a production cost of $30/MWh and the generic gas unit has a production cost of $40/MWh, this analysis would assume that the market price of electricity for all hours when the gas unit is not operational is $35/MWh.
[11] Ayers Direct, p7, lines 3-4.

economics of those generating units. For example, if load growth turns out to be lower than predicted then there will be less demand for supply-side units, which will affect the economics of the units under consideration today. Furthermore, the Company can influence future load growth through energy efficiency programs, as discussed below, which would have important implications for the economics of retrofitting versus retiring the coal units at question today.

3. THE COMPANY'S ECONOMIC ANALYSIS IS INCONSISTENT WITH REASONABLE PLANNING PRACTICE

Q Is the use of a simple spreadsheet evaluation standard practice for investment decisions of this magnitude?

A Not at all. I have now testified or provided analytical support to ten other litigated cases similar to this docket in the last two years,[12] and in no other case have I seen a "back of the envelope" calculation like the one structured in this docket used to attempt to justify charging ratepayers for major capital expenditures. In most other cases, utilities develop estimated market prices for energy and capacity (often under a number of scenarios or uncertainties), run a resource optimization model to determine the best forward-looking portfolio for their system with and without the unit in need of retrofit, and often finalize the analysis with a production cost model to estimate the dispatch and likely costs (or risks) of investing in retrofits versus retirement and replacement of the unit under consideration.

In fact, this Commission recently reviewed a similar application from Duke Energy Indiana (Cause 44217) wherein the utility seeks similar retrofits at a number of coal units. My colleagues at Synapse reviewed this case on behalf of Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch, and while they found several key errors and disagreed with assumptions from Duke, they did not dispute the general economic evaluation methodology employed by Duke.

[12] CPCN, Predetermination, or Applications in: Kansas, Missouri, Georgia, Kentucky (x3), Wyoming, Utah, Wisconsin, and Indiana.

Of note, IPL's 2011 Integrated Resource Plan (IRP) appears to follow a reasonable planning framework, described in the "Scope of Project" provided by Ventyx consultants.[13] This framework includes a market simulation to derive energy and capacity prices, a capacity expansion model to determine new resources, and production cost simulations to "assess performance and risk."

In contrast, however, IPL's case before the Commission provides no support for its projected market prices or market price assumptions, fails to use a least-cost resource optimization, makes broad-based and untested assumptions about dispatch and production cost, uses an atypical and unsophisticated model to determine cost and risk, and does not fully account for potential cost-effective energy efficiency resources on its system.

The Commission should be concerned that the Company has chosen to evaluate the economics of a $511 million investment using a poorly constructed and highly simplistic spreadsheet tool when other comparable utilities use well-established, sophisticated evaluation models. The Company's failure to use an appropriate model for this level of capital investment is unfathomable given that the Company clearly has had experience employing Ventyx to use such models since at least 2009.[14]

It is worth noting that the Oregon Public Utilities Commission (OPUC) recently found that PacifiCorp (dba Pacific Power), a large utility serving five Western states, acted imprudently in installing emissions controls without a sufficiently rigorous analysis. The Commission partially disallowed costs associated with the emissions controls, finding that:

> Pacific Power failed to perform appropriate analyses to determine the cost-effectiveness of the investments. Pacific Power's contemporaneous cost-effectiveness analyses were demonstrably

[13] 2011 IRP provided in CAC-SC DR 1-13, Attachment 2. *See* PDF page 26, page 3 of Integrated Resource Plan Modeling Summary. August 31, 2011. Prepared by Ventyx for IPL.

[14] 2009 IRP provided in CAC-SC DR 1-13, Attachment 4. See PDF pages 31-102. October 5, 2009. Prepared by Ventyx for IPL.

> deficient, and did not demonstrate the rigorous review that a prudent utility should have performed prior to making these significant investments. [15]

I evaluated and testified on the economic justification put forth by PacifiCorp in the above-cited docket. Even PacifiCorp's analysis, ultimately found to be imprudent, was significantly more transparent, logical, and rigorous than the workpapers submitted by IPL in this docket.

Q What is the impact of failing to use a market price model in this case?

A A market price model would have allowed the Company to review a number of risk scenarios, including a range of prices for fuels (e.g. the range of gas and coal prices forecast by Ventyx) and emissions, as well as expected changes in the structure of the electricity market due to impending retirements and changes in MISO loads. By not generating an estimated market price, the Company is restricted from effectively reviewing how their system performs against the MISO market or the degree to which the Company may expect to buy or sell power onto the wholesale market.

Just as importantly, by not evaluating market conditions explicitly, the Company cannot evaluate risks to their fleet posed under different futures or scenarios. As noted by the OPUC in the disallowance against PacifiCorp:

> Major resource decisions should not rely largely on single point forecasts, but should instead be shown to be robust over a wide range of futures/scenarios and input assumptions. … The economics of the utility's projects changed significantly based on changes in the assumptions about single variables such as wholesale prices or closure date. This alone signals that all of the investments should have been stress-tested against a wide range of

[15] Oregon Public Utility Commission. December 20, 2012. In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision. Docket UE 246. Order 12 493.Page 28. http://apps.puc.state.or.us/orders/2012ords/12-493.pdf

> futures and varied input assumptions and that a second stage of more rigorous analyses were merited for a number of the investments. The *ad hoc* analyses that were conducted during this case cannot substitute for the depth and breadth of analyses that should have occurred at the time of the decision. [16]

Q What is the impact of failing to use a resource optimization model in this case?

A Most utilities choose to use a resource optimization tool for this level of planning to identify the most cost effective fleet acquisition choices. IPL's decision to restrict the replacement unit to a comparable CCGT explicitly presumes that the Company requires both the capacity and the energy provided by a CCGT. In addition, this presumption excludes the option of potentially lower cost replacement with market purchases for a period of time, a combination of peaking and baseload units, and/or a portfolio that includes increased demand side management and renewable energy options.

Q What is the impact of failing to use a production cost model or cash flow model?

A Many utilities either parallel or follow-up the use of a resource optimization tool with a production cost model, or export resource optimization outputs into a cash-flow model for further exploration. The purpose of this later step is three-fold: first, a production cost model allows the Company's existing and envisioned resources to be dispatched against expected market conditions, and returns important information about if a plant will earn reasonable revenues on the market; second, many production cost models are able to vary critical inputs to stress-test a given resource portfolio against uncertainty and volatility; third, both production-cost models and cash-flow models are critical to check if assumptions and outcomes are reasonable and internally consistent, and benchmark outcomes

[16] *Ibid* Page 29.

against historic behavior. By failing to implement even a simple cash-flow model, IPL missed critical errors in their analysis.

Q What evidence do you have that the Company does not fully account for potential cost-effective energy efficiency resources on its system?

A First, the evidence provided by the Company indicates that its load forecast does not include enough efficiency savings to comply with the savings goals of the Commission's December 2009 Order under Cause No. 42693. That order requires IPL to gradually increase annual incremental energy savings from 0.3 percent in 2010 to two percent by 2019.[17] However, the Company is expecting to achieve 148 GWh of annual incremental annual savings in 2019, which is only one percent of electricity sales for that year.[18] This is significantly lower than two percent savings, suggesting that significant potential energy efficiency savings are unaccounted for in the Company's planning.

Second, the Company's economic analysis assumes that its energy efficiency programs achieve little to no new savings after 2019, i.e., beyond the Commission's requirement. The Company's load forecast includes roughly 76 GWh of annual incremental energy efficiency savings in 2020 (roughly 0.5 percent of sales); then 19 GWh in 2021; and finally no savings at all in 2022.[19] Clearly the Company is not considering anywhere near the full potential of cost-effective energy efficiency programs after 2019.

[17] Indiana Utility Regulatory Commission, Cause No. 42693, Order December 9, 2009. Page 30 "the Commission finds that electric utilities subject to its jurisdiction shall meet an overall goal of 2% annual cost-effective DSM savings within ten years from the date of this Order."

[18] The annual incremental energy efficiency savings for 2019 is calculated by taking the difference between cumulative savings in 2019 and cumulative savings in 2018. The cumulative energy efficiency savings for 2019 is estimated to be 1,015 GWh, which is equal to the difference between retail sales without energy efficiency (15,393 GWh) and retail sales with energy efficiency (14,378). (Company response to CAC-SC Data Request 2-1a) The cumulative energy efficiency savings for 2018 is estimated to be 867 GWh, which again is the difference between retail sales with and without energy efficiency. Therefore, the annual incremental savings in 2019 are estimated to be 148 GWh, or 1.03% of retail sales.

[19] These annual incremental energy efficiency savings are calculated the same way as the savings for 2019, by taking the difference between cumulative efficiency savings in successive years. (Company response to CAC-SC Data Request 2-1a)

Q What is the impact of failing to fully account for potential cost-effective energy efficiency resources on its system?

A The amount of energy efficiency available on the Company's system over the next ten to twenty years will have significant impacts on the economics of the Company's supply portfolio, including the coal units in question here. In particular, if some or all of the units were to be retired, then the additional energy efficiency could play a critical role in the portfolio of resources that are used to replace the energy and capacity from those units.

Q Are there other ways in which the IPL's analysis is inconsistent with reasonable planning practice?

A Yes. The Company has evaluated the economic outcome of replacing either all, or none, of the Petersburg units – bundling O&M expenditures, assumptions on operational characteristics, and even capital expenditures into a single package. This economic evaluation methodology is fundamentally flawed: by evaluating the whole of the Petersburg plant as a single entity rather than individual units the Company blurs the potentially favorable economic outcome of some units with possible unfavorable economic outcome of others. For example, if a single unit was deeply non-economic, but was analyzed in a package with larger and more economic units, the total package might return an erroneously favorable outcome simply by swamping the non-economic outcome.

4. THE COMPANY'S ECONOMIC ANALYSIS CONTAINS ERRORS AND INCONSISTENCIES

Q How is the Company's analysis erroneous?

A The Company made several significant errors in the construction and execution of the economic analysis. These include the following:

- The growth rate of the consolidated "Dispatch Spread" is mathematically incorrect based on the Company's assumptions;
- The "Dispatch Spread" does not account for the increased variable O&M costs of the coal unit associated with environmental equipment;

- The analysis fails to account for the substantial energy requirement of the environmental equipment being installed either as part of this application, or other necessary environmental equipment not part of this application;
- The analysis assumes that a CCGT replacement unit would have to begin operation in January 2015 – a full year before the MATS deadline, and a full year before the installation date of the MATS equipment at Petersburg Unit 2 and Harding Street Unit 7;
- The analysis fails to include Allowance for Funds Used During Construction (AFUDC) expenses for the environmental equipment; and
- The analysis does not consider or review capital expenditures that the Company could avoid at the coal units between 2013 and 2015 if those units were retired and replaced.

I will describe each of these errors in turn.

Q How is the Company's analysis inconsistent?

A In a number of instances, the Company provided different information in testimony, in Mr. Ayers' workpapers, and in discovery. These include the following:

- The capital cost of "Other" environmental projects is lower in Mr. Ayers' analysis ($[redacted] million)[20] than suggested in table JMA-2 ($480 million) for reasons that are not supported by IPL documentation.[21] Further, the $480 million estimate does not appear to be consistent with estimates provided to IPL, which would suggest capital costs between $237 and $560 million.[22] The analysis has underestimated reasonable risks to the existing coal unit.

[20] The total of all "Other" environmental projects in Ayer's workpapers is equal to $[redacted] million. Found in cells T15 and T16 of tab "OTHER ENVIRO + TOTAL"
[21] Total sum of all projects in the "CAPEX" column in Petitioner's Exhibit JMA-2 ("Future non-MATS Other Environmental Requirements – Preliminary Cost Estimates") is equal to $480 million. Reason cited in workpapers is listed as "closing of ponds – sunk liability".
[22] *See* section below for detailed description of cost components. *See* IPL response to CAC-SC Data Request 1-70a.i. for sources.

- The annual operating costs of "Other" environmental projects in Mr. Ayers' analysis ($[redacted] million)[23] does not appear to be consistent with estimates provided to IPL, which would suggest incremental operating costs between $37 and $71 million per year (after the year 2017).[24] The analysis therefore has significantly understated estimated costs to the Company's coal fleet.
- IPL witness Mr. James Cutshaw recommends a book life of 18 years and a net salvage value of 10% for the environmental equipment,[25] but Mr. Ayers models a 25 year book life for all equipment, starting in 2015.[26] If the Company anticipates recovering the investment over a shorter span to reduce the risk of a stranded investment at the end of the unit's life, the cost of a replacement unit should be included in this analysis.
- Mr. Ayers models the capacity factor of the CCGT replacement unit at 50% from 2015 through 2040, but CAC-SC Data Request 1-43(c) indicates that "the comparative analysis assumed that a CCGT [combined cycle gas turbine] would be dispatched at a 65% capacity factor for the evaluation period." There is no evidence presented in this case to suggest that, under the gas and coal prices contemplated here, that gas-fired units would dispatch each and every year at either 50% or 65% capacity factor. The expected dispatch of a gas unit will depend on assumptions of market prices: under low gas prices or even low, non-zero, CO_2 prices, the gas unit could dispatch at higher capacity factors, while under higher gas prices, the dispatch might be lower than noted here. If the unit is assumed to be dispatched non-economically, the analysis will be biased against the gas replacement.

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[23] The total of all "Other" environmental project operating costs in Ayer's workpapers is equal to $26 million. Found in cells Z17 and Z13 of tab "OTHER ENVIRO + TOTAL"

[24] *See* section below for detailed description of cost components. *See* IPL response to CAC-SC Data Request 1-70b.i. for sources.

[25] Direct testimony of Cutshaw, p5 line 21 to -6, line 1. "IPL requests authority to depreciate the Compliance Project over a period of eighteen (18) years and reflect a negative salvage and removal value of 10%.

[26] *See* Ayers workpapers, tab "Pete MATS (BE with Fuel)" cell C16, and response to CAC-SC Data Request 1-46(d).

- Mr. Ayers models the capacity factor of all of the coal units at 80% from 2015 through 2040, but information provided in CAC-SC DR 1-41(a) "Big Five Generation 2008-2012" indicates that in the last three years, only Petersburg Unit 3 has hit or exceeded an 80% capacity factor. In the last two years, all of the units have remained at or below a 70% capacity factor, with the exception of Petersburg Unit 3 in 2011 (74%) and Petersburg Unit 1 in 2012 (73%). Mr. Ayers presents no information that suggests the capacity factor for these units would improve, or that these units will be able to maintain such output through 2040 when these units are 50-70 years old. There is no evidence presented in this case to suggest that, under the gas and coal prices contemplated here, coal-fired units would dispatch at each and every year at an 80% capacity factor.

Q How does the Company project the relative dispatch costs of running a new CCGT unit compared to their coal fleet?

A The Company estimates the differences in the operating costs (i.e. variable O&M and fuel costs) for a new CCGT and those for its existing coal units, each compared to the forecast power price from CERA. As described in Witness Ayers' testimony, the power price minus the costs of running a gas unit is defined as the "spark spread" while the equivalent for a coal unit is the "dark spread." The difference between the spark and dark spreads is simply equal to the differences in the costs of running a natural gas unit relative to running a coal unit—Ayers refers to this as the "margin spread delta" or the "dispatch spread."

Q Does the Company rely on actual, historical data to develop this "dispatch spread"?

A No, the Company uses a dispatch spread of $[redacted]/MWh in 2015, based on a three-year average of forecasted power and fuel prices from 2014 to 2016.

Q What have the "dispatch spreads" been in recent years?

A The Company calculated historical dispatch spreads in its workbook CAC-SC DR 1-40, Confidential Attachment 1. According to these calculations, the "dispatch spread" has been declining in recent years from $[redacted] in 2010, to $[redacted] in 2011 and -$[redacted] in 2012. In fact, most recently, natural gas has had the dispatch advantage over coal, which is not surprising given currently low natural gas prices. The Company's forecasted "dispatch spread" hinges on the assumption that the recent trend leading to a dispatch advantage for natural gas will reverse, i.e. that by 2015 natural gas prices will return to the levels experienced in 2010 and 2011. This assumption appears to depend on the CERA gas price forecast, which is notably higher than both the Ventyx base forecast and NYMEX futures through 2016.[27]

Q How does the Company forecast the "dispatch spread" after 2015?

A The Company starts with the $[redacted] per MWh spread in 2015, adjusts this to the CCGT penalty value of $9.14 per MWh, and then escalates the CCGT penalty value annually by a factor of 1.45% in real terms (3.95% including inflation) each year.[28],[29] This annual growth rate is based on the differences in the annual growth rates of natural gas and coal price forecasts: on average, natural gas prices forecasts grow at 2.25% per year while coal price forecasts grow at 0.8% per year.

Q Is the Company's methodology for estimating the growth rate of the dispatch spread mathematically correct?

A No. Witness Ayers seems to conflate two separate concepts:

1. the annual growth of the dispatch spread, and
2. the separate growth rates of the components of the spread itself, namely the operating costs of coal and natural gas plants.

[27] In 2015, CERA forecasts gas prices of $4.45/MMBtu (2012$, 2.5% inflation). Both NYMEX and Ventyx forecast gas prices of $4.01/MMBtu (2012$) in 2015.
[28] Described in Ayers Direct, p10
[29] While the CERA values are not derived explicitly, a rough calculation suggests that the starting spread value would be about $7.88/MWh using Ventyx gas prices instead of CERA prices.

Taking the difference between the annual growth rates of each of these components (2.25% - 0.8% = 1.45%) is <u>not</u> the same as the annual growth rate of the difference.[30]

The correct method, given Mr. Ayers' apparent intentions, would have been to simply apply the individual annual growth rates of each component (2.25% and 0.8%, respectively) and then take the difference between the two results—this is the dispatch spread. Instead, Mr. Ayers applies the growth rate difference (1.45%) to the spread.

Figure 1 shows a simple, hypothetical case for a coal and natural gas plant to show the Company's calculations along with the mathematically correct method. This example starts with the $[redacted]/MWh spread projected by the Company for 2015 then projects the spread through 2040. The Company's method (in red) assumes a constant 1.45% annual growth rate while (in green) the annual growth predicted from increasing the operating costs by 2.25% annually for natural gas and 0.8% for coal, leads to a different annual growth rate of the spread in each year—starting at 5.5% in the first year, then decreasing in each year. The differences in methodology shown in this example demonstrate widely different levels for the dispatch spread: the Company's method yields a dispatch spread of $16 in 2040. The mathematically correct method yields a dispatch spread of $33 in 2040.

[30] In making this mathematical error, Mr. Ayers has violated a basic algebraic concept – the distributive property.

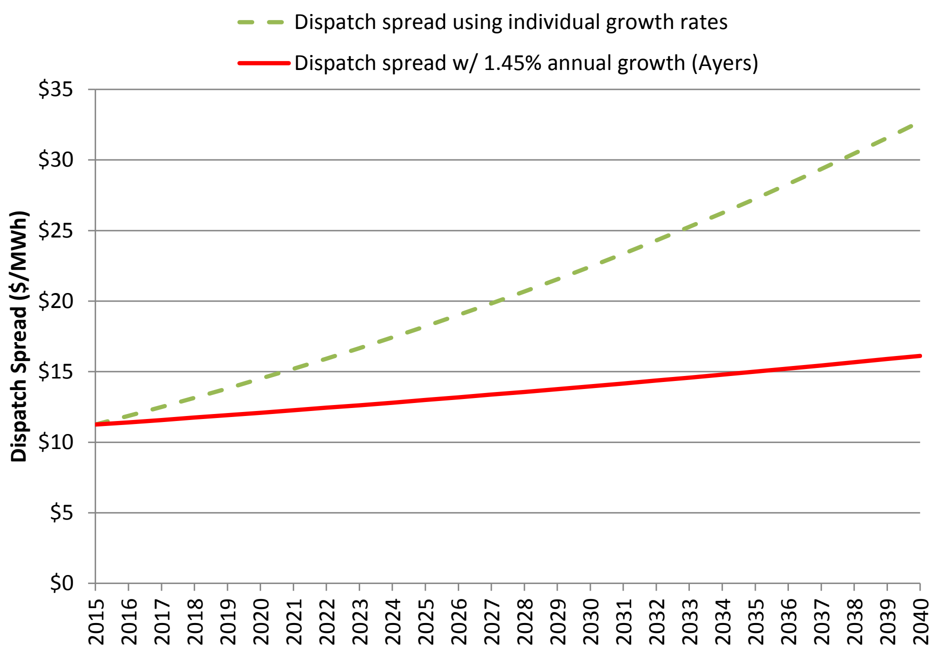

Figure 1. Hypothetical dispatch spread for coal and natural gas plants. Y-axis is the dispatch spread in $/MWh.

Q What is the impact of correcting this error?

A The correction of this error shifts the analysis in favor of the retrofit decision; yet as I will show later, this correction is not sufficient to show that retrofitting all of the IPL Big Five units will remain economic.

Q Is the starting value of the dispatch margin critical to the Company's forecast?

A Absolutely. The Company chose a starting value of $[redacted] per MWh for the dispatch margin in 2015, based on CERA's forecasts of coal and gas prices in 2014-2016.[31] If the Company had started with the most recent data available from 2012, the first year's margin would have been -$[redacted] per MWh. Then, if subjected to Mr. Ayers' methodology of applying the difference in forecast growth rates, this dispatch spread would become <u>increasingly negative</u> in each year. I doubt that Mr. Ayers would approve of this assumption. However, simply

[31] It should be noted that the CERA gas prices are markedly higher in these years than the Ventyx forecast supplied by the Company.

applying his methodology to the current dispatch spread would yield far different results than when starting from a 2015 projection.

Q Please describe why you think that the "Dispatch Spread" does not account for the increased variable O&M costs of the coal units from environmental equipment.

A The "Dispatch Spread" factor is constructed from CERA estimates of how the variable cost of electricity from a generic gas unit will compare to the wholesale market price in any given time period relative to the variable cost of electricity from a generic coal unit. For example, on a given hour will the variable cost of electricity from a generic gas unit be less than the wholesale market price, resulting in it being dispatched on that day, or will it be above the market price, resulting in it not being dispatched into the wholesale market. This estimate contains no information about the specifics of the coal units under consideration (or even the replacement gas unit, for that matter). However, the Petersburg and Harding Street 7 units will all face increased operating costs once the environmental equipment is installed. Indeed, the Company estimates that the variable O&M costs of the coal units will anywhere from double to quadruple once MATS and other environmental equipment are installed,[32] raising variable O&M costs as high as $6.80/MWh on Petersburg 4 – over [redacted] times higher than the variable O&M costs of a new CCGT, according to the Company's CERA estimates.[33]

Under this additional cost burden, Mr. Ayers' estimated 2015 "coal dispatch advantage" would shrink by [redacted]%.

[32] *See* CAC-SC DR 1-48 Supp Response Attachment 1. With the addition of MATS and "Other" variable O&M costs, variable O&M increases 196%, 303%, 237%, 215%, and 374% at Harding Street 7 and Petersburg 1-4, respectively.

[33] *See* Mr. Ayers direct testimony workpapers, tab "16 CERA New Plant Cost" cell D12.

Q Why do you think that existing O&M expenses should grow faster than shown in Mr. Ayers' model?

A The Company provided aggregate O&M and capital costs for the Petersburg and Harding Street plants,[34] but claimed that "a breakdown of O&M was not performed nor was it needed for IPL's baseload comparative evaluation."[35] Over a month after the initial data request, the Company finally provided O&M costs broken down by unit for the year 2012 and implied that they should be simply inflated by 2.5% per year. However, reviewing the Company's initial response to the same request[36] and Mr. Ayers' workpapers,[37] it is clear that O&M expenses grow far faster than inflation at 2.5%. In fact, the total O&M and capital expenditures in Mr. Ayers' workpapers grow at 4.6% per year, or 2.1% faster than inflation.

I have not adjusted this factor in my alternative analysis, but consider it highly questionable.

Q What are the energy requirements of the environmental retrofits considered in this case?

A According to the Company, the environmental retrofits contemplated in this case will reduce the energy output of the Big Five units by nearly 14 MW (see Table 3, below).

Table 3. Parasitic load requirements for environmental equipment. Source: CAC - SC DR 1-48, Supp. Response Att. 1, Table 1

Unit	Parasitic Load (kW)
Petersburg 1	1,185
Petersburg 2	3,079
Petersburg 3	4,042
Petersburg 4	2,990
Harding Street 7	2,439

[34] *See* Ayers confidential workpapers, tab "O&M+Fixed 10-Year (2)", as well as response to CAC-SC 1-48c&d, workpaper "CAC-SC DR 1-48cd, Attachment 1 (MATS1A-Tate-Total Capital + Expense O&M - Summary By Group1).xlsx"

[35] Supplemental response to CAC-SC DR 1-48 (c,d, i, j): "IPL in its evaluation used a total O&M cost including variable and fixed capital and expense O&M for Petersburg plant... A breakdown of O&M was not performed directly nor was it needed for IPL's baseload comparative evaluation."

[36] Response to CAC-SC DR 1-48c&d, file "CAC-SC DR 1-48cd, Attachment 1 (MATS1A-Tate-Total Capital + Expense O&M - Summary By Group1).xlsx"

[37] *See* tab "O&M+Fixed 10-Year (2)"

Total	**13,735**

It is not clear if these parasitic load requirements reflect only the equipment requested in this case, or also include additional environmental equipment considered by the Company in Petitioner's Exhibit JMA-2.[38]

Q Was the parasitic load requirement included in Mr. Ayers' analysis?

A No. In a Company-provided spreadsheet, indicating the assumed summer rated capacity of each coal unit from 2012 through 2031, none of the units considered here showed a decrease in available capacity.[39]

Including the parasitic load of the environmental retrofits in the analysis reduces the value of the retrofit coal plants. First, these coal plants would have a lesser contribution to system reliability than stated by the Company. Second, to the extent that the production costs (not total cost) of coal actually are lower than that of gas, every additional MWh of energy attributed to a coal unit is an incremental net benefit. If the coal unit is unable to produce as many MWh because of a de-rate, the net production benefit will be lower. Finally, a de-rated plant is unable to spread fixed and capital costs across as many MWh, increasing its incremental cost on a per MWh basis.

Q Do these retrofits have other impacts on the performance of the coal plants?

A Yes. Generally, these retrofits would be expected to impose a heat rate penalty on the coal units as well. Because additional power is required in all or most hours in which the environmental equipment is in use, the overall efficiency of the coal

[38] One of the largest investments in the non-MATS environmental equipment list is an SCR at Petersburg 4. This equipment typically has a fairly large parasitic load, and does not appear to be represented in this table.

[39] CAC-SC DR 1-41c. "Please provide, by month and by unit, individual, any projections of generation, available capacity, and heat rate used or considered for this filing for Petersburg 1-4 and Harding Street 7 for the years 2012-2040." Company provided worksheet "CAC-SC DR 1-41c, Confidential Attachment 2 (MATS1D-Tate-SummerRatedCapacity_Projection_10_11a).xls" with non-changing values in all years. In response to CAC-SC DR 1-48a, requesting "net available summer capacity, exclusive of all environmental projects" the Company cited to the previous response.

unit decreases, meaning that the unit will burn more fuel for the same energy production.

Q Did the Company estimate or use a heat rate penalty in their analysis of the retrofits?

A No. In answer to a query from interveners, the Company responded that "IPL has not estimated the revised heat rates" associated with the environmental projects.[40]

Q What is the compliance deadline for MATS?

A The MATS rule requires that the standard be met by April 2015, with a potential extension to April 2016 at the discretion of the Indiana Department of Environmental Management.[41] The U.S. EPA has indicated that requested extensions until April 2016 will likely be granted.

If the Company demonstrated that it planned to meet MATS by repowering or replacing any of its coal units, it would likely have until April 2016 to replace the unit. Mr. Ayers has assumed a January 2015 replacement date, making the replacement option more expensive than necessary.[42]

According to workpapers attached to supplemental testimony, retrofits at Petersburg 1, 2, and 4 are all expected to be completed by April 2015, while the retrofits at Petersburg 3 and Harding Street 7 are expected to be completed by April 2016. I have adjusted the assumed in-service dates for Petersburg 3 and Harding Street 7 accordingly in my analysis.

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[40] *See* response to CAC-SC 1-48h.

[41] "Existing sources may be provided up to 3 years after the effective date to comply with the final rule; if an existing source is unable to comply within 3 years, a permitting authority has the ability to grant such a source up to a 1-year extension, on a case-by-case basis, if such additional time is necessary for the installation of controls." 77 Fed.Reg 9304, 9407 (Feb. 16 2012). In this case the "Effective date is April 16, 2012." 77 Fed.Reg 9304. Therefore, the latest possible compliance date, with the one-year extension, is April 16, 2016.

[42] The timing of the retrofits, while important, does not impact the analysis results as much as the timing of the replacement unit, due to the higher upfront capital impact of the replacement unit. Deferring this large-scale investment has a large impact on the present value of the decision.

Q Does the Company's analysis include AFUDC for the environmental retrofits?

A No. Generally, the Company would expect recovery for the cost of money in the form of AFUDC or Construction Work in Progress (CWIP). Unless the Company expects to forgo such recovery, I would have expected to see this in the Company's analysis. Mr. Ayers' analysis cites directly to numbers in Petitioner's Exhibit TWM-5 ("IPL MATS Compliance: Total Cost Summary")[43] which clearly notes that "Project Total…Excludes Removal Costs and AFUDC."[44]

However, the CCGT cost from CERA <u>does</u> include both financing costs and interest during construction.[45] By including this value in the replacement unit but <u>not</u> in the environmental costs, the Company has biased their analysis against replacement.

In my analysis, I have used the updated capital costs for the environmental equipment supplied by Mr. Cutshaw in workpapers for supplemental testimony per Exhibit TWM-S3. These values also exclude AFUDC. [46] I added 15% to the cost of these retrofits to capture some component of AFUDC.[47]

Q What is the importance of reviewing capital expenditures at the Company's coal units between 2013 and 2015?

A The Company is conducting an evaluation of the benefit of either retrofitting or retiring existing units. Those units require ongoing maintenance, but also require large capital expenditures on a regular basis – such as the replacement or refurbishment of major equipment. However, if the Company were to retire a plant in the next few years, it is quite likely that a large proportion of these costs can either be scaled back or avoided altogether. For example, it is probably unnecessary to upgrade a turbine for improved performance if the plant will only

[43] Now replaced with values in Petitioner's Exhibit TWM-S3, with similar note.
[44] *See* Petitioner's Exhibit TWM-5, note at bottom of page.
[45] *See* Ayers workapers, tab "16 CERA New Plant Cost", footnote 10: "Total capital cost figures include owner's costs- development/permitting, land acquisition, construction G&A, financing costs, interest during construction, etc."
[46] TWM Workpapers for Supplemental Direct Testimony indicate "Exclusive of Demolition Costs and AFUDC"
[47] Assumes projects are built over approximately 3 years with an assumed AFUDC rate of 5.5%.

operate for another two years. These avoidable costs are important considerations in a retrofit/retirement evaluation such as this one; by not excluding avoidable capital costs, the Company biases the analysis towards the continued operation of the coal units.

Q Why did the Company not review avoidable capital expenditures between 2013 and 2015?

A The Company explains why these costs were not calculated in response to CAC-SC DR 1-50:

> Costs from 2013-2015 were not included in the future life cycle cost evaluation. These costs would however be included in a retirement evaluation if the future life cycle evaluation had indicated a unit's economic viability was in question. A retirement evaluation, if determined necessary, would also include the premature unit retirement costs and timing impacts, an economic assessment of common O&M shared by plant to determine what O&M is actually avoided, and any additional environmental compliance costs for plant and system based environmental rules, such as NOx. This additional retirement evaluation was not needed as the Big Five units and Compliance plan showed superior economics.

The Company's logic is deeply flawed. Each of the costs considered in this explanation are avoidable through the retirement of the coal unit. The only reason that the Company perceives the economics of the Big Five units to be "superior" is that they have systematically ignored or undervalued avoidable costs and biased their analysis towards a certain outcome.

Finally, it is unclear why the Company did not simply perform the "retirement evaluation" referenced here. Such an analysis should be fairly straightforward for a large, multinational Company such as AES. Clearly, IPL has been able to procure expertise for their IRP planning process. The costs of performing such an analysis are *de minimis* compared to the half billion dollars contemplated in this case.

Q Why do you think that the Company's estimate of "Other" environmental capital costs does not capture the full range of risk to the IPL coal units?

A The Company's analysis presents a table of capital costs for "other environmental" projects, including the proposed 316(b) water intake rule, the proposed CCR rule, expected NAAQS changes, and expected changes to NPDES permitting rules governing effluent from waste ponds.[48] These costs amount to $[redacted] million. Similar costs are laid out in Petitioners Exhibit JMA-2, but the total of these costs amounts to $480 million. It appears that the difference between these estimates is due to costs for coal pond remediation that the Company considers "sunk," or unavoidable; i.e. the Company will have to pay those costs regardless of if the units are maintained or retired.

The Company provided several documents that ostensibly provide the basis of these cost estimates. In review of these documents, it is difficult to corroborate the values used by the Company in the economic evaluation. I have compiled the Company's estimate of these "Other" environmental regulations ("Ayers") in Table 4, below, and my estimates from the documentation provided by the Company for a low and high range.

Table 4. Estimated capital costs for "other" environmental projects. Estimates from Company analysis and from company documentation. In millions 2012$.

	Ayers[49]	Low	High
316(b)	[redacted]	$7	$155
CCR	[redacted] [50]	$26 [51]	$26 [52]

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[48] Table is found in Ayers workpapers tab "OTHER ENVIRO + TOTAL" columns U through Y.
[49] As cited in Ayers workpapers.
[50] Includes reduction of $[redacted] million (from $[redacted] million) due to "closing of ponds – sunk liability"
[51] Cost represents total of capital cost for Subtitle D implementation of CCR rule (referred to as "Regulation Da – status quo Beneficial Use" for Petersburg and Harding Street plants ($29.7M and $28.0M respectively) minus all capital costs for "Pond Closures" at Petersburg and Harding Street ($20.5 and $11.25M, respectively). In AECOM, December 13, 2010.
[52] Cost represents total of capital cost for Subtitle C implementation of CCR rule (referred to as "Regulation C – no beneficial use" for Petersburg and Harding Street plants. Costs are identical to Subtitle D.

NAAQS[53]	[redacted]	$130	$130
NPDES[54]	[redacted]	$75	$250
Sum	[redacted]	**$238**	**$561**

The document with 316(b) costs has scenarios that range from a total of $7 million to as high as $155 million, if new cooling towers are required.[55] The document cited for NAAQS dates from 2004, and does not address the potential costs of an SCR at Petersburg 4, as shown in Petitioners Exhibit JMA-2.[56] The capital costs associated with CCR compliance were obtained from a Contractor document prepared in 2010,[57] and include compliance costs for regulation under a strict control scenario ("Subtitle C") and a less strict scenario ("Subtitle D"), with a variety of outcomes for the beneficial use (or not) of coal combustion residuals. The capital costs were the same for both CCR scenarios. These costs exclude any pond or impoundment closure costs, which are assumed to be unavoidable. The Company did not provide any documentation supporting the cost for effluent treatment under the NPDES permit guidelines.

Overall, the estimates compiled by Mr. Ayers do not span the range of capital risk known and considered by the Company. According to Company documents, these costs could be as low as $238 million, or as high as $561 million for the Big Five units.

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[53] Assumed same as Ayers.

[54] *See* Company written reponse to CAC-SC DR 1-70a.i paragraph 4. "Current preliminary estimates range from $75M - $250M."

[55] *See* CAC-SC DR 1-14, Attachment 1 (316b Report - Legal Memo Redacted), tables 5 & 6. Low costs are "Option 1"; high costs are "Option 3"

[56] Multi-Pollutant Emission Compliance Study. Report No. SL-008273. Prepared for Indianapolis Power and Light by Sargent and Lundy, July 29, 2004.

[57] "Summary of Memorandums Evaluating the Effect of Proposed Regulation of Coal Combustion Residuals by US EPA." Prepared by AECOM for IPL, December 13, 2010.

Q Why do you think that the Company's estimate of "Other" environmental operating and maintenance costs understate the likely costs to the IPL coal units?

A The Company's analysis also presents estimates of total O&M costs associated with all of the "other environmental" projects,[58] and response to CAC-SC DR 1-70a.i indicates that these values are derived from the same documents as the capital costs for other environmental projects, noted previously.

Again, it is difficult to corroborate the Company's numbers as shown in this document, and a review of the documents actually suggests that the O&M numbers are higher than presented by Mr. Ayers. Table 5, below, shows the O&M costs as estimated by the Company in the analysis, and as determined from Company documentation. Specific citations are given in footnotes.

Table 5 Estimated O&M costs for "other" environmental projects. Estimates from Company analysis and from company documentation. In millions 2012$.

	Ayers	Low	High
316(b) [59]	[redacted]	$1	$6
CCR	[redacted]	$18[61]	$47[62]
NAAQS[63]	[redacted]	$3	$3
NPDES[64]	[redacted]	$15	$15
Sum	[redacted]	**$37**	**$71**

[58] Table is found in Ayers workpapers tab "OTHER ENVIRO + TOTAL" cells U17 to X17.
[59] *See* CAC-SC DR 1-14, Attachment 1 (316b Report - Legal Memo Redacted), tables 5 & 6. Low costs are "Option 1"; high costs are "Option 3"
[60] Includes adjustment for annual "status quo" costs.
[61] Cost represents total of storage and disposal costs post 2017 for Subtitle D implementation of CCR rule (referred to as "Regulation Da – status quo Beneficial Use") for Petersburg and Harding Street plants ($16.5M and $7.3M, respectively) less annual "status quo" costs ($3.15M and $2.2M, respectively). In AECOM, December 13, 2010.
[62] Cost represents total of storage and disposal costs post 2017 for Subtitle C implementation of CCR rule (referred to as "Regulation C – no Beneficial Use") for Petersburg and Harding Street plants ($36.2M and $16.4M, respectively) less annual "status quo" costs ($3.15M and $2.2M, respectively). In AECOM, December 13, 2010.
[63] Company response to CAC-SC DR 1-70b.i indicates that "IPL has completed a study which included costs for a Unit 4 SCR. One study… provided a cost estimate of $2.3M annually in 2005 dollars." Inflated to 2012$, this value is $2.7M, or $3M rounded.
[64] Company states in response to CAC-SC DR 1.70b.i that "IPL is currently in the process of performing a Wastewater Treatment Study to determine costs associated with compliance with the new NPDES Permit requirements. This study is still underway and O&M costs have not yet been developed." Assume Company value.

From information that I have been able to find from the Company's cited documentation, the O&M values for "other" environmental projects appear to be significantly understated by Mr. Ayers. The high-end of these costs ($71M per year) are significantly above the Company's analyzed values. Correcting for these would add another $690 million into the PVRR of operating the Big Five coal units.

5. THE COMPANY'S ECONOMIC ANALYSIS DOES NOT EXPLORE ADEQUATE ALTERNATIVES

Q What alternatives to the environmental retrofits did the Company evaluate?

A The Company limited its evaluation of resource options to replacement of the entire five units with new CCGT capacity. This is a simplistic option which is not necessarily the least expensive alternative strategy available to the Company. The Company could, and should, have considered other alternative strategies composed of some mix of the other resources available to it. In the near term these include market purchases or purchase power agreements (PPA), and the ownership of a CT to meet capacity requirements in addition to some CCGT. In the longer term these include increased demand-side management (DSM), or a mix of renewable energy and capacity provisions. Over the 2015 to 2040 period the Company should have evaluated a portfolio approach with a mix of additional demand reduction, self-owned capacity, and a balance of energy through market sales and purchases.

The Company considered none of the above, restricting it's analysis to the review of a single CCGT resource.

Q Why did the Company only explore a CCGT replacement?

A The Company explains why no other resources were tested in the response to CAC-SC 1-23(a-k):

> The economic analysis of the Big Five's continued operation was based on a comparison to a new CCGT. The analysis methodology used was not to determine what resource to replace a retired coal

> unit with, but rather to determine if IPL's compliance project was economic.

This reasoning is fallacious. The Company could have compared the continued operation of the Big Five units against <u>any</u> one type of electric generating capacity, but this would not guarantee that a compliance project is economic or not. Presumably, the Company seeks, or is charged with seeking, the lowest cost reasonable solution for ratepayers, and if this lower cost solution is anything <u>other</u> than solely a CCGT, then the Company will have failed to find a reasonable alternative to the coal units. Simply because the Company perceives the coal units to be less expensive than a CCGT does not, and should not, imply that a CCGT is the only alternative that it should explore.

The Company cites a further reason for choosing the CCGT, because "CCGT generation is the low cost resource selected in IPL's most recent IRP and is also the basis for the resource selection IPL is currently pursuing to replace the retiring Eagle Valley unit and fill other capacity requirements."[65] While it may be true that an optimized analysis conducted over a year ago suggested a new CCGT resource, this may not be the most efficient outcome when reviewing a larger block of retiring capacity.

It is particularly puzzling that the Company has an IRP process by which optimal new resources are supposed to be selected to meet the Company's needs, but the Company chose not to use this established economic evaluation methodology to review the cost effectiveness of half a billion dollars' worth of retrofits at these particular coal units.

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[65] Response to CAC-SC 1-23(a-k)

6. THE COMPANY'S ECONOMIC ANALYSIS DOES NOT EXPLORE ADEQUATE RISK

Q Does the Company's analysis in this docket provide an adequate review risks or uncertainties?

A No. The Company explored a single sensitivity that I consider functionally flawed and insufficient. In his baseline analysis, Mr. Ayers used the difference between a generically-derived "spark spread" and "dark spread" to estimate the production cost difference between a generic coal unit and a generic gas unit, referred to as the "dispatch spread" or CCGT "Penalty."[66] The sensitivity employed by Mr. Ayers is simply to cut this margin in half to "to reflect perpetual long term low natural gas prices, or some form of restrictive climate change legislation (but most likely not both due to their positive price correlation).…"[67]

Q Why is this sensitivity functionally flawed and insufficient?

A First, the sensitivity is functionally flawed for the same reason that the initial estimate of the growth of the 'dispatch spread' is flawed. As I explained earlier, the difference between the growth rate of two factors cannot be used to project the growth rate of the margin between those two factors. Therefore, any projections or estimates derived from this faulty and mathematically incorrect logic is also functionally flawed. Further, the sensitivity is insufficient because Mr. Ayers has excluded any possibility that the margin between coal and gas could not only shrink from his projections, but could feasibly invert at reasonably anticipated gas prices <u>or</u> coal prices.

I illustrate a series of conditions below in which the "dispatch spread" shrinks or inverts at reasonably anticipated projected commodity prices. Using CERA's assumptions for heat rates and the Company's Ventyx-supplied coal and gas prices (as utilized in Mr. Ayers' analysis),[68] I created an estimate of the production cost margin under base conditions in Figure 2, below (solid black

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[66] *See* generally Ayers Direct pages 9-10.
[67] *See* Ayers Direct p14 line 21 through p15 line 1.
[68] Coal heat rate = 10,500 btu/kWh; gas heat rate = 7,000 btu/kWh. *See* Ayers Direct footnote 1 on p9.

line). I then substituted in the Ventyx "low" case gas price.[69] The margin under the low gas price assumption <u>never</u> exceeds zero meaning that gas remains competitive with coal throughout the analysis period (see dotted black line). This is a far different story than simply cutting the margin (the "dispatch spread") in half.

In the figure below, I also show the margin with the base Ventyx gas price and the Synapse low CO_2 price.[70] Under this circumstance, the margin hovers around zero once the CO_2 price is in place. At higher CO_2 prices, the margin inverts and gas is competitive. Again, Mr. Ayers' assumption of a margin cut in half is not an effective sensitivity.

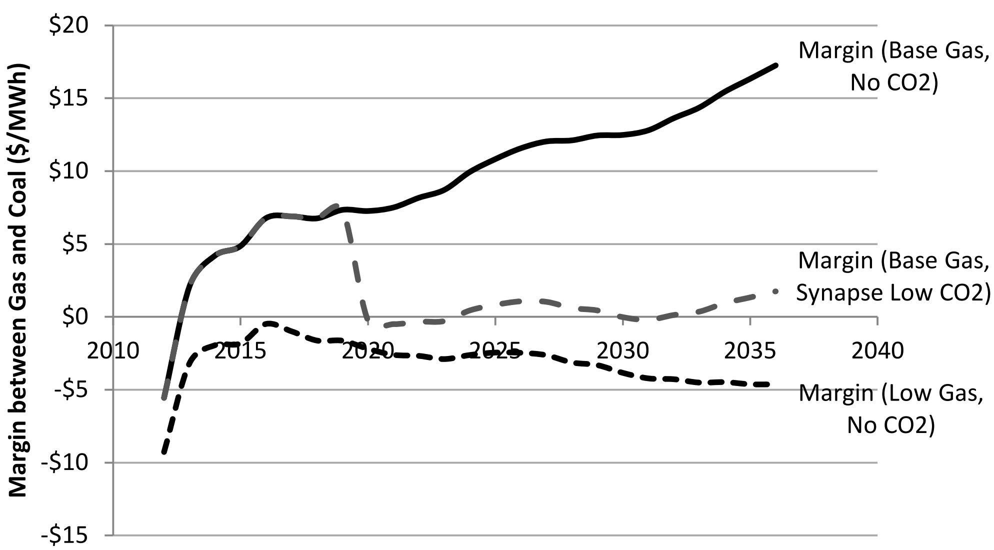

Figure 2. Margin between gas and coal production cost at base coal prices.

[69] According to the IP&L 2011 IRP, the Ventyx low (and high) gas price is at the 10% confidence limit. In other words, Ventyx judges the low gas price to have a 10% probability of occurrence. A description is found in the IRP (provided in CAC-SC DR 1-13, Attachment 2), p27. [redacted]

[70] Assumes gas has a CO_2 emissions rate of 0.5t/MWh and coal has an emissions rate of 1.0t/MWh. Synapse low CO_2 price begins at $15/t$CO_2$ in 2020 and rises linearly to $35/t$CO_2$ in 2040.

It is notable that the margin in 2012 was negative, and there are several realistic circumstances in which a negative or zero dollar margin could either persist or return. Interveners asked if the Company had "consider[ed] a stress test in which the current margin… is maintained"[71] to which the Company responded that a case where the energy margin is maintained "at 2014-2016 levels would not economically challenge IPL's Big Five coal fired generation…" However, the Company did not test the <u>current</u> zero dollar margin. If the Company had performed a zero dollar margin stress test, the Company would have found that, even under Mr. Ayers' method, each and every coal unit fails to pass the economic screen.

Q Do you have a recommendation for a more comprehensive set of sensitivities?

A Yes. I recommend that the Company explore the bounds of both high and low gas prices and high and low prices for CO_2 emissions. Such a sensitivity should explore, at the very least, bookends of combinations that both favor and penalize the decision to retrofit – including high gas prices in the absence of a CO_2 price <u>and</u> low gas prices in the presence of an aggressive CO_2 price, as well as high and low coal prices.

Synapse produced an updated CO_2 price forecast in 2012. This forecast reviews legislative efforts, potential rulemaking, and a large number of utility CO_2 forecasts from the last two years. The forecast and report are attached as Exhibit JIF-2. The forecast contains a Mid estimate, which begins at \$20/tCO_2 in 2020 and rises to \$65/tCO_2 by 2040. This estimate is bounded by a Low and High, which represent uncertainty limits.

It is noteworthy that the Company's 2011 IRP explored two non-zero CO_2 price trajectories developed by Ventyx, a "moderate CO_2" and a "high CO_2" case.[72] It appears that the levelized cost of the Synapse Mid case approximates the Ventyx high case, and the levelized cost of the Synapse Low case approximates the

[71] CAC-SC 1-62c.
[72] IP&L 2011 IRP (provided in CAC-SC DR 1-13, Attachment 2), pages 27 and 45.

Ventyx moderate case. The impact of this magnitude of cost has been reviewed by IPL as recently as October 2011.

Q What is Mr. Ayers' opinion on the relationship between CO_2 and gas prices?

A Mr. Ayers states that "natural gas prices would likely be positively correlated with CO_2 prices."[73]

Q What is the implication of this statement?

A The assertion that "natural gas prices would likely be positively correlated with CO_2 prices" means that it would be his underlying assumption that in the presence of CO_2 prices, natural gas prices must rise. Such a restriction prevents the Company from reviewing any scenario in which CO_2 prices are implemented and natural gas prices remain at their normally projected prices.

Q Does he provide supporting evidence for this assertion?

A No. He simply states that such a correlation is reflected in the Ventyx study.

Q Is there information available about the potential linkage between gas prices and CO_2 prices?

A There is very little, if any, independent research (by which I mean not an assertion from a conflicted party) on the connection between gas and CO_2 prices, and while others have asserted such a connection, the evidence for such a correlation is thin.

The Energy Modeling Forum (EMF) is a collaborative independent research group that draws together a large number of expert "individuals represent[ing] a mix of corporate, academic, and government perspectives."[74] Leading institutions at EMF include such entities as the Edison Electric Institute (EEI), the Electric Power Research Institute (EPRI), Brattle, the Energy Information Administration (EIA), the American Petroleum Institute, a number of U.S. national laboratories, international academic programs, and energy companies. EMF working groups

[73] Ayers Direct, p13 line 12.
[74] http://emf.stanford.edu/docs/about_emf

design, run and evaluate integrated energy economic models designed to explore integrated market fundamentals.

The latest released EMF working group report from March 2011 included long-run models from ten independent organizations, including (amongst others) EIA, Massachusetts Institute of Technology (MIT), the Pacific Northwest National Laboratory, Charles River Associates, and Resources for the Future. Among the scenarios modeled were base-case and carbon-tax scenarios.[75]

In Figure 3, below, I have plotted the percentage change in natural gas prices in relation to a range of carbon prices as output by each model in this study.

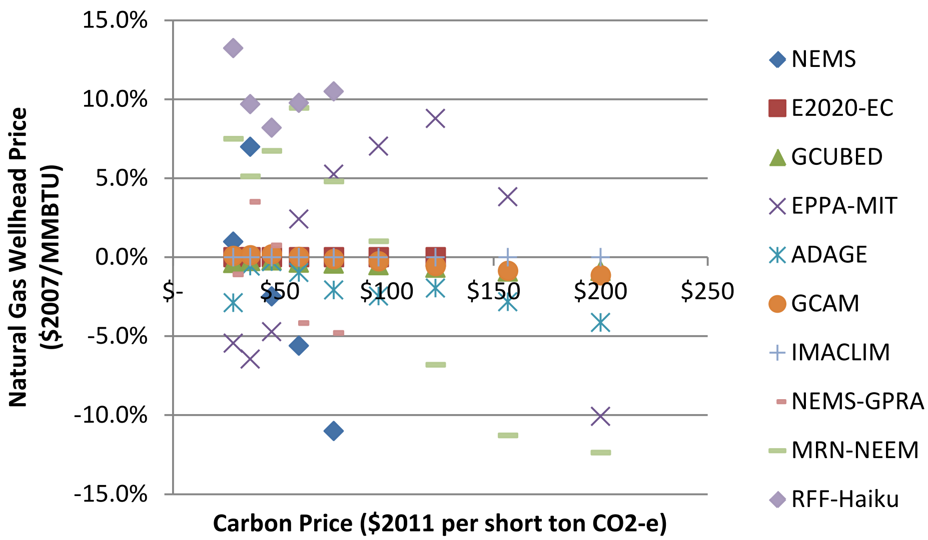

Figure 3. Model results from EMF indicating natural gas changes with rising CO_2 prices.[76]

Figure 3 shows clearly that some of the most advanced integrated energy economics models disagree with one another regarding the extent of gas price sensitivity to carbon prices. Of the ten models portrayed here, four predict <u>lower</u>

[75] In these scenarios, the carbon tax is imposed on all fossil energy users.
[76] Data available at http://emf.stanford.edu/docs/263. NEMS (US Energy Information Administration), E2020-EC (Environment Canada), GCUBED (Brookings Institution), EPPA-MIT (Massachusetts Institute of Technology), ADAGE (Research Triangle Institute), GCAM (Joint Global Change Research Institute, Pacific Northwest National Laboratory), IMACLIM (Centre International de Recherche sur l'Environnement et le Développement), NEMS-GPRA (US Department of Energy & Onlocation, Inc.) MRN-NEEM (Charles River Associates), and RFF-Haiku (Resources for the Future)

gas prices, four predict higher gas prices, and two are unchanged compared to the baseline at any carbon price below \$60/ton CO_2.[77] At carbon prices above \$60/ton the majority of models consistently predict lower gas prices than the baseline.

Therefore, it is my opinion that Mr. Ayers' statement regarding the connection between CO_2 and gas prices is unfounded.

Q Does the Company's sensitivity analysis explore different load trajectories?

A No. Mr. Ayers' analysis is restricted to a one-to-one replacement of coal with gas, and is not able or equipped to examine different changes in demand. Therefore, it is unable to determine if the Company would even require the capacity or energy from Petersburg or Harding Street 7 in future years under different load scenarios.

7. SYNAPSE'S ECONOMIC EVALUATION MODEL

Q Are you able to evaluate the Company's findings based on Mr. Ayers' analysis?

A No. While Mr. Ayers stipulates that his "spreadsheet evaluation [was performed] for both simplicity and transparency… and not to precisely define the PVRR [present value revenue requirement] for any plan,"[78] his spreadsheet is so fraught and filled with erroneous and inconsistent assumptions that I am unable to even modify his spreadsheet to adjust it for internal consistency or test alternate sensitivities. Some of his assumptions are both fundamental to his findings and filled with numerous, unstated assumptions.

For example, Mr. Ayers compresses the relative performance of coal- and gas-fired generation in the MISO market into a single value. This value should be dependent on a number of assumptions including the shape of the supply curve for MISO Cinergy in any given year, the specifications of the gas and coal unit under consideration (such as variable cost, heat rate, and emissions rates), the price of gas, the price of coal, the relationship between the CERA gas price

[77] With the exception of the \$36/ton CO_2 mark, in which 5 of 10 predict a higher gas price.
[78] Ayers Direct, p7 lines 3-4

forecast to 2016 and the Ventyx gas price forecast after 2016, and any emissions prices for criteria pollutants or CO_2. Yet there is no way to identify, much less evaluate, any of those assumptions from the single value used by Mr. Ayers.

Q How are you able to evaluate the cost effectiveness of the coal retrofits, if not through the Company's analysis?

A I developed a cash flow model to "define the PVRR" for each coal unit and potential replacement CCGT unit. I did not have the time or opportunity to develop potentially lower cost alternatives, such as market purchases, capacity-only resources, or demand-side management.

Q Did the Company provide sufficient information to construct such a model?

A No. Interveners requested detailed information almost certainly held by the Company, including unit performance data, expected annual O&M costs, and expected capital expenditures,[79] as well as market prices for any scenarios contemplated by the Company for this case or otherwise.[80] Eventually, the Company provided 2012 fixed and variable O&M broken out by unit. It is unclear if these values include annual capital expenses incurred at the coal station, or not. I have assumed, for the sake of a conservative assumption, that they do include such capital expenses.

The Company did not provide estimated hourly market prices until January 22, 2013 – one week before the submission of this testimony[81] – and the average annual prices appear to be inconsistent with the average annual prices provided from the Ventyx assumptions provided to interveners in a previous discovery response.[82]

[79] CAC-SC DR 1-48 a-k; CAC-SC DR 1-64(c).
[80] CAC-SC DR 1-64(b); CAC-SC DR 3-4 b-c, 3-5 b-c
[81] See response to CAC-SC DR 3-3a,b
[82] See CAC-SC DR 1-47b, Confidential Attachment 1 (Midwest_Spring 2012_Power_Reference_Case_-_Data_Supplement_IPL).xlsx, tab "13. Annual MCPs", column "Average" for region MISO-IN.

Q Please describe the purpose of your cash flow model, as well as its major input variables and dispatch methodology.

A My model is set up to estimate the incremental revenue requirements of each coal unit, and potential replacement gas unit, in each year from 2015 to 2040. This is the "cash flow" associated with each unit in each year. The model then calculates the present value of this stream of annual incremental revenue requirements, i.e. the PVRR.

The key input variables for each of the Big Five coal units from 2015 through 2040 are:

- Fuel cost,[83]
- Non-environmental variable O&M expenses,[84]
- Non-environmental fixed O&M expenses,[85]
- Non-environmental ongoing capital costs,[86]
- Environmental variable O&M,[87]
- Environmental fixed O&M,[88]
- Environmental project capital costs,[89] inflated by an AFUDC estimate[90] and capitalized using the same economic evaluation methodology and variables employed Mr. Ayers;[91] and
- CO_2 emissions costs.[92]

[83] Coal costs derived from Ventyx Coal Prices as presented in Ayers Direct workpapers. Heat rates derived from EIA Form 923 EIA Form 923, Schedule 3A and 5A for 2011. Capacity for each coal unit is equal to Ayers assumed capacity minus parasitic load as shown in response to CAC-SC DR 1-48g. Capacity factors from 2015-2040 derived from Synapse market price and dispatch model as described later in this testimony.
[84] Source: CAC-SC DR 1-48 Supplemental Response Attachment 1 (January 15, 2013), multiplied by generation
[85] Source: CAC-SC DR 1-48 Supplemental Response Attachment 1 (January 15, 2013)
[86] Assumed, conservatively, to already be included in fixed O&M category
[87] Source: CAC-SC DR 1-48 Supplemental Response Attachment 1 (January 15, 2013), multiplied by generation
[88] Source: CAC-SC DR 1-48 Supplemental Response Attachment 1 (January 15, 2013)
[89] Source: TWM supplemental testimony workpapers, per TWM-S3.
[90] AFUDC adder assumed at 15%, generally consistent with a 5.5% AFUDC rate on 3-4 year investments shown in TWM supplemental testimony workpapers.
[91] *See* Ayers Direct workpapers, tab "Pete MATS (BE with Fuel)", lines 8-16

The key inputs for the CCGT units include:

- Fuel cost,[93]
- Non-environmental variable O&M expenses,[94]
- Non-environmental fixed O&M expenses,[95]
- Capital cost,[96]
- CO_2 emissions costs,[97] and
- Market purchases.[98]

The model dispatches the coal units and the gas units against predicted locational marginal prices (LMP) in the Cinergy/Indiana hub. It uses the results of that dispatch to calculate the absolute costs of fuel, variable O&M, and emissions for each unit in each year. The model purchases sufficient energy from the market in each year to make up the difference, if any, between the MWh from the coal unit and the replacement gas unit in any year that gas dispatches less than coal. Conversely, if the gas unit dispatches more than coal, market sales are assumed.

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[92] Zero, Synapse Low, Mid, and High price estimates from 2015-2040. CO_2 emissions rates derived from US EPA Air Markets Program Data (http://ampd.epa.gov/ampd/) for Petersburg and Harding Street 7 units, year 2011.

[93] Natural gas costs derived from Ventyx Gas Prices as presented in Ayers Direct workpapers. Heat rate of 6,750 btu/kWh from Ayers Direct workpapers ("INPUT SUMMARY"). Capacity for the gas unit is equal to the coal unit under comparison. Capacity factors from 2015-2040 derived from Synapse market price and dispatch model as described later in this testimony.

[94] Source: Ayers Direct workpapers ("INPUT SUMMARY").

[95] Source: Ayers Direct workpapers ("INPUT SUMMARY").

[96] Source: Ayers Direct workpapers ("INPUT SUMMARY"); CERA notes that "total capital cost figures include owner's costs- development/permitting, land acquisition, construction G&A, financing costs, interest during construction, etc.", assumed to include AFUDC.

[97] Zero, Synapse Low, Mid, and High price estimates from 2015-2040. CO_2 emissions rate (0.48 tCO_2/MWh) is set equal to weighted average 2010/2011 CO_2 emissions rate of all CCGT in Indiana, Illinois, and Ohio, from US EPA Air Markets Program Data (http://ampd.epa.gov/ampd/).

[98] Market purchases are equal to total annual MWh difference between coal and gas dispatch, multiplied by weighted average market cost for all hours in which coal and gas unit are differently dispatched. If the coal unit is dispatched more than the gas unit, the market purchases are a net cost to the CCGT replacement option. If the coal unit is dispatched less than the gas unit, the market purchases are a net benefit to the CCGT replacement option. MWh differences and market prices derived from Synapse market price and dispatch model as described later in this testimony.

The model calculates the present value revenue requirement (PVRR) of the annual incremental revenue requirements of each unit. I have assumed that if the Company were to plan to retire a coal unit, it could operate through the latest MATS deadline of early 2016. Therefore, the replacement CCGT is not required in my analysis until 2016. The only costs incurred in the analysis in 2015 are the capital and O&M expenditures associated with new environmental equipment at the coal unit.[99] In 2016, both the coal unit and the CCGT replacement unit begin incurring full costs.

The difference between the PVRR of the coal cost stream is compared to the PVRR of the gas cost stream, and the absolute difference is reported as the <u>net benefit of retiring the coal unit</u> (i.e. positive values represent a benefit of retirement).

I performed this analysis for each of the IPL Big Five coal units individually in each of twelve different scenarios: every combination of low, medium, and high gas prices (as supplied to the Company by Ventyx) and zero, low, medium, and high CO_2 prices (as produced in the Synapse 2012 price forecast).

Q How did you develop hourly market prices for these twelve scenarios?

A Without access to a regional dispatch tool for this case, I derived estimated future market prices for Indiana based on a statistical representation of five years of hourly locational marginal prices (LMPs) for the Cinergy/Indiana hub,[100] MISO regional loads,[101] and natural gas prices[102] from 2007 through 2011, inclusive. I assumed that generally the LMP is a function of gas price and load level, and that the load shape of MISO is closely correlated with the load shape in Cinergy/Indiana (as the latter is not available from public data). I found statistics

[99] The analysis assumes that in 2015 both scenarios will require the operation of the coal plant, and therefore fuel, base O&M and base capital expenses are incurred in both – or in this case, neither – scenario.
[100] Source: MISO. Cinergy hub 1/1/2007 through 12/31/2011. Indiana hub 1/1/2012 to 1/10/2013.
[101] Source: FERC Form 714. 1/1/2006-12/31/2008 compiled from all utilities in MISO region; 1/1/2009-12/31/2011 from MISO regional load.
[102] Monthly historic prices from US Energy Information Administration (EIA) Short Term Energy Outlook (STEO)

that describe the relationship between gas, regional load, and LMP prices which are shown schematically in **Figure 4**, below. This figure demonstrates that as gas prices rise (lighter shades of blue), the supply curve becomes steeper – an expected and reasonable trend.

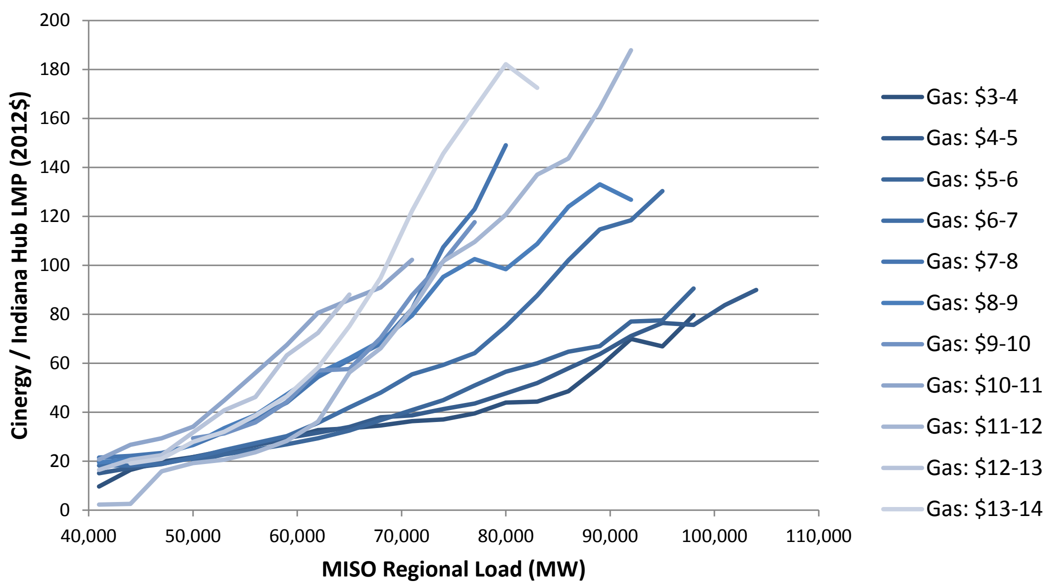

Figure 4. Cinergy / Indiana LMP historic supply curves, shown as a function of MISO regional load and gas price (all 2012$).

Using this economic evaluation methodology and a fixed hourly load shape, I could estimate hourly LMPs based on predicted gas prices, such as the Ventyx forecast provided by the Company. I used the load shape for 2011 to represent a generic load curve.

I added in CO_2 price impacts into the load shape by assuming that approximately the lower third of the supply curve is comprised of coal on the margin with a 1.0tCO_2/MWh emissions rate, and the upper third is comprised of gas on the margin with a 0.6tCO_2/MWh emissions rate. I assumed the middle third, from 53,000 MW to 77,000 MW, gradually changes from a coal to gas mix on the margin.

Using the statistical relationship between gas, load, and LMP, and including the CO_2 price adder, I am able to project an estimate of hourly LMPs for each of the twelve gas and CO_2 scenarios.

This economic evaluation methodology makes a number of simplifying assumptions, and is by no means a deterministic model. Rather, it is a basic economic evaluation methodology by which I could provide reasonable estimates for hourly market prices.

Q **Does your estimate of market prices compare favorably with actual LMPs?**

A Yes. While the average behavior does not capture the highest peaks nor the deepest troughs, or random perturbations in the market (due to constraints or outages), the statistically-derived LMPs appear to perform well against historic LMPs. In Figure 5, below, I've plotted annual average historic Cinergy/Indiana LMPs from 2007-2011, and predicted annual average LMPs from the statistical model. These two appear to track well over the historic period.

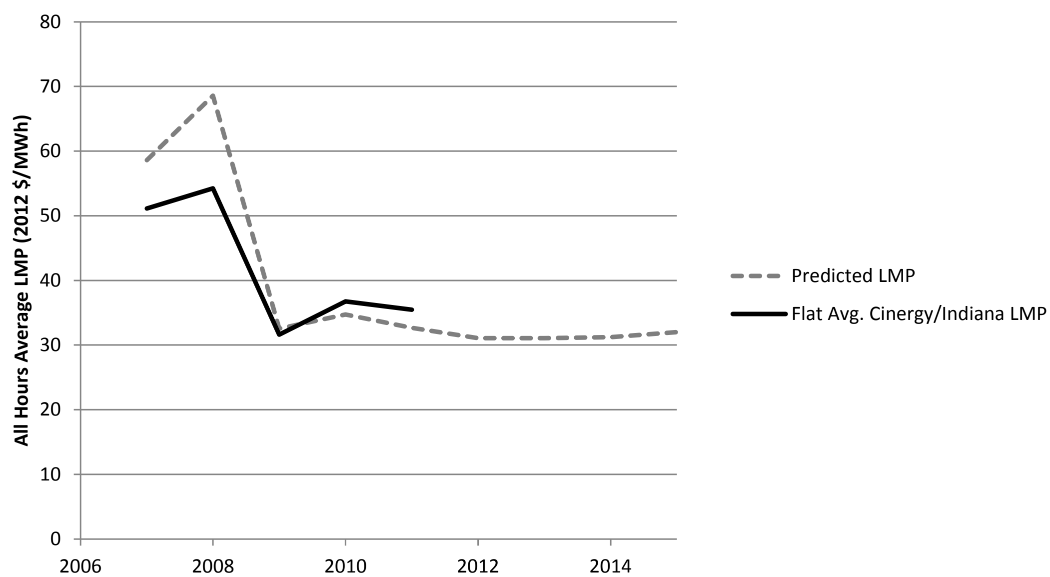

Figure 5. Statistically-predicted all-hours Cinergy/Indiana LMPs plotted against historic all-hours (flat average) LMPs.

On an hourly basis, the statistically predicted LMP also tracks well against historic LMPs. Figure 6 shows predicted and historic hourly Cinergy/Indiana

LMPs in a one month period in late 2010. Again, the statistically-predicted LMPs do not capture all of the nuances of the historic LMPs, but provides a reasonable benchmark.

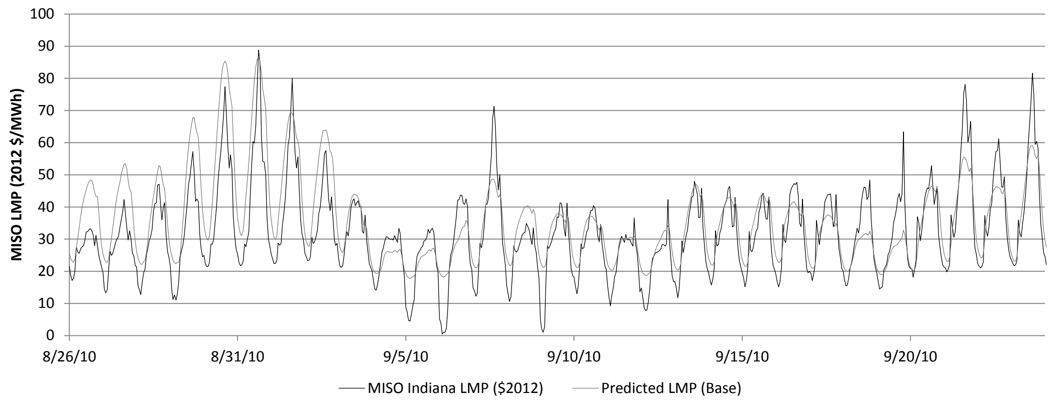

Figure 6. Hourly statistically predicted Cinergy/Indiana LMPs plotted against historic hourly LMPs for a representative period.

The economic evaluation methodology employed here is necessarily limited: it cannot capture changes in the composition of the MISO market, retirements, or new entrants. It is based on a single historic load shape (2011) and there is no guarantee that future load behavior will approximate historic loads. However, for lack of a reasonable range of market prices provided by the Company under a reasonable set of risk scenarios, and for lack of a production-cost model run by the Company for the purposes of evaluating this retrofit decision, the market estimate shown here is an improvement over the back-of-the-envelope calculations provided by Mr. Ayers.

Q How does the model dispatch the coal and gas units against market prices?

A The model dispatches the Big Five units and the CCGT replacement units against market prices using an algorithm that I derived from a review of historic dispatch data. For this review, I have compiled the average behavior of each coal unit and a proxy natural gas unit (the Lawrenceburg plant, a 1,100 MW CCGT in Dearborn County, Indiana). The behavior is characterized as the average amount of output (in MW) produced by a unit at different LMP price points, after accounting for the fuel and variable cost of the unit. This behavior is characterized with a simple formula that captures the minimum LMP at which a unit begins operation, the LMP at which it runs full out, and the slope connecting those points. I use this information to estimate the dispatch of each unit under consideration. Ultimately, this economic evaluation methodology returns an estimated annual capacity factor for each coal unit and the proxy CCGT unit, as well as the weighted average market price of the marginal hours in which one unit operates but the other does not.

Q How does the model's predicted dispatch compare to actual historic capacity factors?

A Again, while the economic evaluation methodology is not perfect, it does a reasonable job representing historic dispatch. Figure 7, below, shows the predicted capacity factor of the Petersburg 1 coal unit and the Lawrenceburg CCGT proxy unit plotted against the historic capacity factor of both.

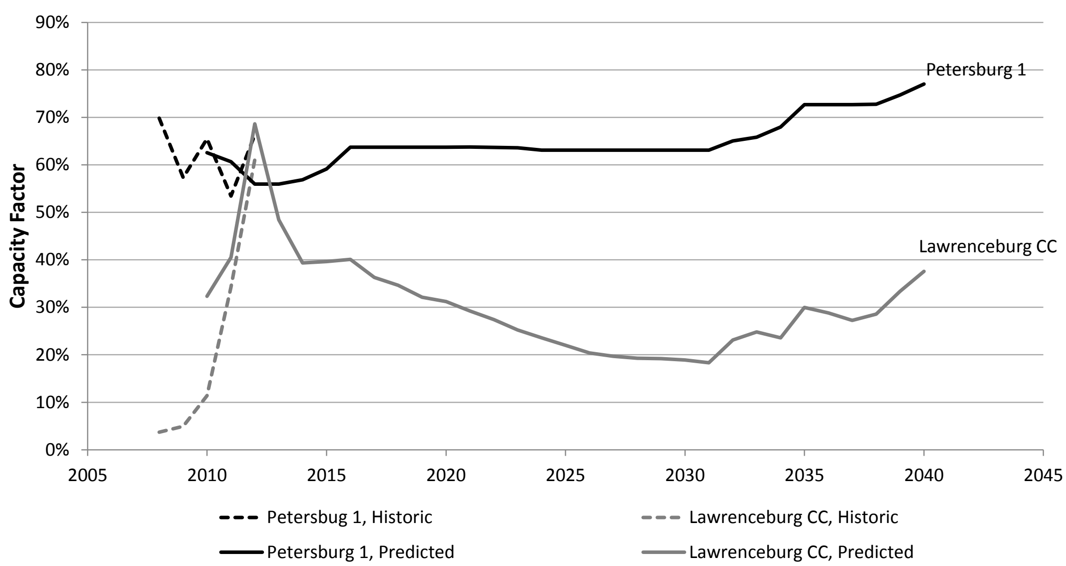

Figure 7. Historic and predicted dispatch for Petersburg 1 and the Lawrenceburg CCGT proxy replacement unit under base Ventyx gas prices and no CO_2 price.

Q Would you recommend using your predicted market prices and estimated unit dispatch as a replacement for a production cost model?

A No. These estimates serve to stand in for the opaque and insufficient back-of-the-envelope calculation performed by the Company in this docket. This model does not replace a competently considered and executed production cost model to derive market prices.

Q Would you recommend using your cash flow analysis as a replacement for a resource optimization model study?

A No. Again, these estimates serve to fill deep gaps in the Company's calculation and economic evaluation methodologies. While I believe that the values derived from my analysis are reasonable for consideration in this docket, my analysis does not replace a study prepared using a more sophisticated resource optimization model. Again, it is particularly puzzling that the Company was able to use sophisticated modeling to prepare its 2011 IRP, but was unable or unwilling to use that modeling capability to evaluate the economics of its proposed investments in this docket.

8. Findings and Recommendation

Q Please summarize the outcome of your analysis for the IPL Big Five Units.

I performed an economic evaluation of all of IPL's Big Five units using a range of gas and CO_2 price forecasts, and almost all other inputs held constant with the Company's assumptions. For the gas prices, I used the Company's Ventyx forecasts through 2036, extrapolated through 2040. For CO_2 prices, I used the Synapse 2012 forecast, as well as a zero price. I consider the combination of the mid gas and mid CO_2 forecast to be the most likely combination. The results of this analysis, as the net benefit of retiring Petersburg Unit 1 and replacing it with a CCGT unit, is shown in

A Table 6, below.

Table 6. Net benefit (PVRR) of retirement for Petersburg 1, in 2012$ millions, under different gas and CO2 price assumptions.

Petersburg 1		Natural Gas Forecast		
		Low	**Medium**	**High**
CO_2 Price Forecast	**Zero**	$63	($90)	($336)
	Low	$137	$3	($213)
	Mid	$150	$81	($125)
	High	$179	$114	($74)

Universally, all of the coal plants perform fairly well under the Ventyx high gas price sensitivity, and perform poorly under the Ventyx low gas price sensitivity. While all of the units remain somewhat economic under an assumption of no CO_2 price at base Ventyx gas prices, Petersburg Units 1 & 4 are completely marginal (i.e. an economic toss-up) at low CO_2 prices and clearly non-economic at the Synapse Mid- and High-CO_2 prices. Petersburg Unit 2 becomes highly non-economic even at Low-CO_2 prices.

My analysis shows that Petersburg Units 1, 2, and 4 are the most likely candidates for retirement, rather than retrofit, based on the magnitude of the net PVRR of retiring them.

Q Please discuss Petersburg Unit 1.

In

A Table 6, above, I show the outcome of my analysis under different gas and CO_2 price forecast assumptions for Petersburg Unit 1. Positive values indicate a <u>net benefit</u> for retirement, while negative values indicate that the analysis favors the retrofit. At a low gas price with an assumption of <u>no</u> CO_2 price, the analysis indicates that retirement is favorable by a PVRR of $63 million. Conversely, at high gas prices with no CO_2 price, the analysis indicates the retrofit would incur a benefit of $336 million.

Notably, as long as the gas price is high, the analysis favors the retrofit; when gas prices are low, the analysis universally favors retirement. Under the expected gas price forecast (medium), Petersburg Unit 1 favors a retrofit only in the circumstance that there is no CO_2 price or equivalent policy implemented in the next 25 years. With an assumption of a Synapse "low" CO_2 price, Petersburg Unit 1 is marginal ($3 million benefit for retirement). Assuming that the Company's projections of capital expenses and O&M remain valid, and no other costs are incurred at Petersburg Unit 1, there would be an approximately equivalent value to maintaining or retiring the Petersburg 1 unit with a low CO_2 price. However, in my estimation, the Synapse Mid case is a more reasonable planning future – and under this scenario, Petersburg Unit 1 should be considered for retirement (a benefit of $81 million towards retirement).

Q Please discuss Petersburg Units 2, 3, and 4 and Harding Street Unit 7.

A The outcome of this analysis is similarly structured for the other Petersburg units and Harding Street Unit 7. Table 7, below, shows that Petersburg Unit 2 is only economic to retrofit under an assumption of no CO_2 price. Even at fairly low CO_2 prices, the unit shows a net benefit towards retirement.

Table 7. Net benefit (PVRR) of retirement for Petersburg 2, in 2012$ millions, under different gas and CO2 price assumptions.

Petersburg 2		Natural Gas Forecast		
		Low	**Medium**	**High**
CO_2 Price Forecast	**Zero**	$188	($130)	($601)
	Low	$251	$230	($335)
	Medium	$286	$158	($156)
	High	$344	$212	$137

Table 8 through Table 10 show similar analysis results for Petersburg Units 3 and 4, and Harding Street Unit 7.

Table 8. Net benefit (PVRR) of retirement for Petersburg 3, in 2012$ millions, under different gas and CO2 price assumptions.

Petersburg 3		Natural Gas Forecast		
		Low	**Medium**	**High**
CO_2 Price Forecast	**Zero**	($100)	($412)	($1,010)
	Low	$109	($181)	($695)
	Medium	$125	$17	($482)
	High	$179	$55	($250)

Table 9. Net benefit (PVRR) of retirement for Petersburg 4, in 2012$ millions, under different gas and CO2 price assumptions.

Petersburg 4		Natural Gas Forecast Low	Medium	High
CO_2 Price Forecast	Zero	$72	($269)	($843)
	Low	$152	($7)	($436)
	Medium	$188	$60	($184)
	High	$257	$116	$142

Table 10. Net benefit (PVRR) of retirement for Harding Street 7, in 2012$ millions, under different gas and CO2 price assumptions.

Harding Street 7		Natural Gas Forecast Low	Medium	High
CO_2 Price Forecast	Zero	$11	($316)	($794)
	Low	$157	($68)	($484)
	Medium	$171	$57	($277)
	High	$202	$125	($56)

The net benefit of retirement for Petersburg Unit 4 is similar to that of Petersburg Unit 1. Under a zero CO_2 price forecast, the unit may be economic, but it is economically marginal (again, a toss-up) at even low CO_2 prices, and clearly non-economic at the recommended Synapse Mid CO_2 price.

Petersburg Unit 2 and Harding Street Unit 7 show a less decisive economic outcome. While both continue to favor retirement at the Synapse Mid CO_2 price, the balance is less clear at these two units. These units are moderately balanced around the CO_2 price risk – i.e. if CO_2 prices are at the low forecast range, ratepayers are benefited (on an order of magnitude) as much as they would be penalized should CO_2 prices be at the high range. Again, these units show a clear benefit to retirement at low gas prices, and a clear benefit to replacement at high gas prices.

My analysis may also understate the value of retirement for each of the Big Five Units, as I have not:

- accounted for the higher “other” environmental project O&M costs described in the Company’s documentation (discussed earlier in my testimony),
- accounted for avoidable capital costs in the 2013-2015/2016 timeframe if some or all of the coal units were to be retired,
- performed an analysis with higher coal prices
- performed an optimization model with portfolio replacement,
- estimated savings incurred by replacement or partial replacement with energy efficiency or other DSM, or
- reviewed opportunities to purchase market capacity or energy for an interim period to reduce ratepayer impacts.

Q Can you draw any conclusions on the basis of your analysis?

A Yes. First, for reasons that I have outlined above, the Company’s analysis is clearly flawed, erroneous and biased. The Commission should disregard it in full.

Second, my analysis suggests that Petersburg Units 1, 2, and 4 are candidates for retirement, and, thus, the Commission should deny CPCN in this docket.

Further, prior to receiving a CPCN for Petersburg Unit 3 and Harding Street Unit 7, the Company should submit an analysis demonstrating to the Commission’s satisfaction that these units are, in fact, reasonable investments.

I recommend that the Commission require the Company to conduct a detailed and expansive modeling study of Petersburg Unit 3 and Harding Street Unit 7 using analytical methods commensurate with the scale of investment considered by the Company in this docket. Such an analysis should include a reasonable range of commodity price risks for coal and gas prices, emissions price risks for both CO_2 and criteria pollutants (under, for example, a re-issued Cross-State Air Pollution Rule), and continue to include estimated or proxy costs for proposed and emerging environmental regulations. The analysis should consider all feasible and cost effective capacity and energy replacement options, including DSM and efficiency, renewable energy, capacity resources, and coal unit repowering. The

Commission should grant a CPCN to these units only if such an analysis demonstrates decisively that ratepayers will face lower costs and risks under a retrofit scenario than under any other least cost replacement plan.

Q Does this conclude your testimony?

A It does.

VERIFICATION

I, Jeremy I. Fisher, PhD, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Jeremy I. Fisher, PhD

1/28/2013

Date

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

JANICE CONYERS

EXHIBIT JIF-1

Jeremy I. Fisher, PhD

Curriculum Vitae

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EMPLOYMENT

Scientist **2007 - present**
Synapse Energy Economics

Postdoctoral Research Scientist **2006 - 2007**
Tulane University, Department of Ecology and Evolutionary Biology
University of New Hampshire, Institute for the Study of Earth, Oceans, and Space

Visiting Fellow **2007 - 2008**
Brown University, Watson Institute for International Studies

Research Assistant **2001 - 2006**
Brown University, Department of Geological Sciences

EDUCATION

Ph.D. Geological Sciences	**2006**	Brown University, Providence, Rhode Island
M.Sc. Geological Sciences	**2003**	Brown University, Providence Rhode Island
B.S. Geology	**2001**	University of Maryland, College Park, Maryland
B.S. Geography	**2001**	University of Maryland, College Park, Maryland

TESTIMONY

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Fisher, J.I. E. Hausman, and C. James. Emissions Behavior in the Northeast from the EPA Acid Rain Monitoring Dataset. Northeast States for Coordinated Air Use Management (NESCAUM), Boston, MA. January 30, 2008.

Fisher, J.I. J.F. Mustard, and M. Vadeboncoeur. Climate and phenological variability from satellite data. Ecology and Evolutionary Biology, Tulane University. March 24, 2006.

Fisher, J.I., J.F. Mustard, and M. Vadeboncoeur. Anthropogenic and climatic influences on green leaf phenology: new observations from Landsat data. Ecosystems Center at the Marine Biological Laboratory. Woods Hole, MA. Seminar, September 27, 2005.

Fisher, J.I. and J.F. Mustard. High resolution phenological modeling in Southern New England. Woods Hole Research Center. Woods Hole, MA. Seminar, March 16, 2005.

TEACHING

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Teaching Assistant	**2002 & 2004**	Estuarine Oceanography, Brown University

FELLOWSHIPS

2007 Visiting Fellow, Watson Institute for International Studies, Brown University
2003 Fellow, National Science Foundation East Asia Summer Institute (EASI)
2003 Fellow, Henry Luce Foundation at the Watson Institute for International Studies, Brown University

UNIVERSITY SERVICE

Representative	**2005-2006**	Honorary Degrees Committee, Brown University
Representative	**2004-2006**	Graduate Student Council, Brown University

EXHIBIT JIF-2

Synapse
Energy Economics, Inc.

2012 Carbon Dioxide Price Forecast

October 2, 2012

AUTHORS

Rachel Wilson, Patrick Luckow, Bruce Biewald, Frank Ackerman, and Ezra Hausman

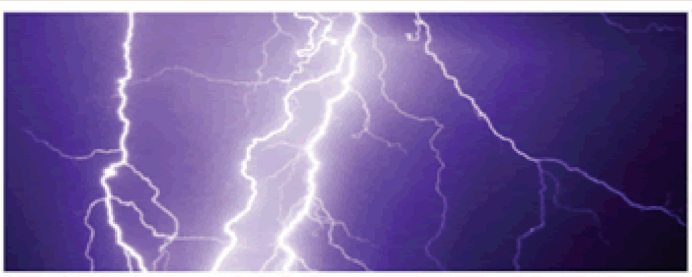

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Table of Contents

1. Executive Summary

Electric utilities and others should use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. Estimating this price can be difficult because, despite several focused attempts, the federal government has not come to consensus on a policy (or a set of policies) to reduce greenhouse gas (GHG) emissions in the U.S.

Although this lack of a defined policy certainly creates challenges, a "zero" price for the long-run cost of carbon emissions is not a reasonable estimate. The need for a comprehensive effort in the U.S. to reduce GHG emissions has become increasingly clear, and it is certain that any policy requiring, or leading to, these reductions will result in a cost associated with emitting CO_2 over some portion of the life of long-lived electricity resources. Prudent planning requires a reasonable effort to forecast CO_2 prices despite the considerable uncertainty with regard to specific regulatory details.

This 2012 forecast seeks to define a reasonable range of CO_2 price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. This forecast updates Synapse's 2011 CO_2 price forecast, which was published in February of 2011. Our 2012 forecast incorporates new data that has become available since 2011, and extends the study period end-date to 2040 in order to provide useful CO_2 price estimates for utilities planning 30 years out into the future.

A. Key Assumptions

Synapse's 2012 CO_2 price forecast reflects our expectation that cap-and-trade legislation will be passed by Congress in the next five years or so, and the resultant allowance trading program will take effect in or around 2020. These assumptions are based on the following reasoning:

- We believe that a federal cap-and-trade program for GHGs is a key component of the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost.
- We believe that federal legislation is likely by the end of the session in 2017 (with implementation by about 2020) prompted by one or more of the following factors:
    - technological opportunity;
    - a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action;
    - a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies; and
    - increasingly compelling evidence of climate change.

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. Historically, this pattern of states and regions leading with initiatives that are eventually superseded at a national level is common for energy and environmental policy in the US. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

In addition to the assumptions regarding a federal GHG program described above, this paper also expects that regional and state policies will lead to costs associated with GHGs in the near-term (i.e., prior to 2020). Prudent planning requires that utilities take these costs into account when engaging in resource planning.

B. Study Approach

To develop its 2012 CO_2 price forecast, Synapse reviewed more than 40 carbon price estimates and related analyses, including:

- McKinsey & Company's 2010 analyses of the marginal abatement costs and abatement potential of GHG mitigation technologies
- Analyses of the CO_2 allowance prices that would result from the major climate change bills introduced in Congress over the past several years, including analyses by the Energy Information Association (EIA) and the Environmental Protection Agency (EPA)
- The U.S. Interagency Working Group's estimates for the social cost of carbon
- Analyses of the factors that affect projections of allowance prices, including analyses by the EIA and Resources for the Future
- CO_2 price estimates used by utilities in a wide range of publicly available Integrated Resource Plans

Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of the various Congressional proposals to date offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

Synapse also considered the impact on CO_2 prices of regulatory measures outside of a cap-and-trade program—such as a federal Renewable Portfolio Standard—that could simultaneously help to achieve the emission-reduction goals of cap-and-trade. These "complementary policies" result in lower CO_2 allowance prices, since a smaller amount of CO_2 reductions would need to occur under the cap-and-trade program.

C. Synapse's 2012 CO_2 Price Forecast

Based on analyses of the sources described above, and relying on its own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. These cases represent different appetites for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040.[1] This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario).
- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets (nationally or internationally); restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; or higher baseline emissions.

Table ES-1, below, presents Synapse's Low, Mid, and High case price projections for each year of the study period, as well as the levelized cost for each case.

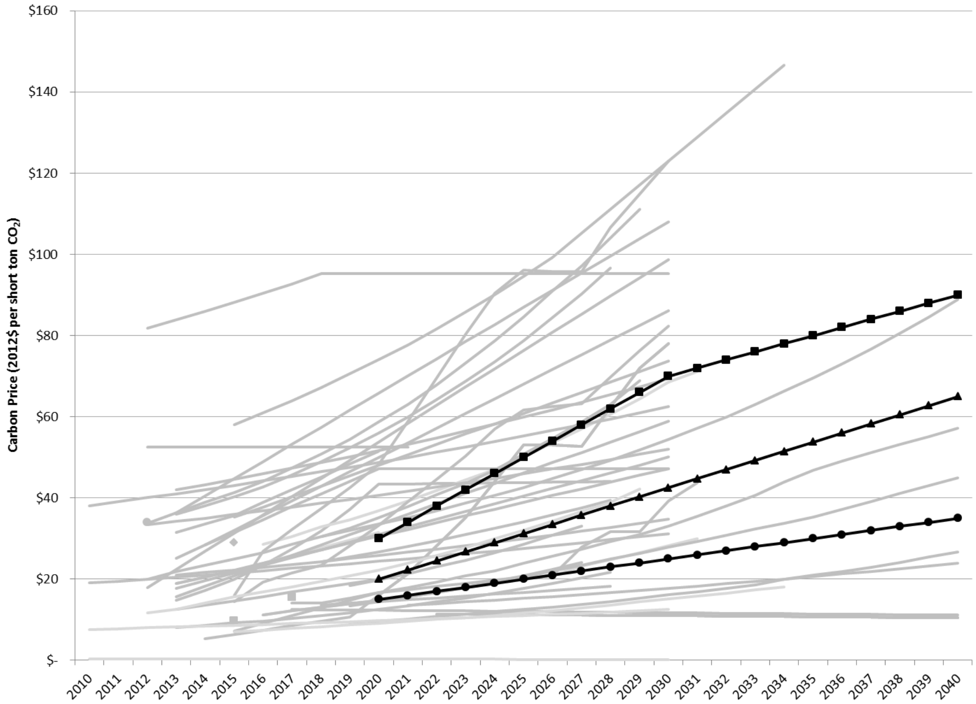
[1] Throughout this report, CO2 allowance prices are presented in $2012 per short ton CO2, except in reference to a few original sources, where alternate units are clearly labeled. Results from other modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis. Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Results originally provided in metric tonnes were converted to short tons by multiplying by a factor of 1.1.

Table ES-1: Synapse 2012 CO_2 Allowance Price Projections (2012 dollars per short ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

Figure ES-1, below, presents Synapse's Low, Mid, and High price forecasts as compared to a broad range of CO_2 allowance prices used in utility Integrated Resource Planning to date. Synapse forecasts are represented by black lines, while utility forecasts are represented by grey. As shown in this figure, Synapse's projections lie solidly in the middle of the utility forecasts.

Figure ES-1: Synapse forecasts compared to a range of utility forecasts



2. Structure of this Paper

This paper presents Synapse's assumptions, data sources, and estimates of reasonable future CO_2 prices for use in resource planning analyses. The report is structured as follows:

- Section 3 discusses the key assumptions behind Synapse's estimates
- Sections 4 through 8 present data from the sources reviewed by Synapse in developing its estimates of the future price of CO_2 emissions
- Section 9 presents Synapse's 2012 Low, Mid, and High CO_2 price forecasts, and compares these projections to a range of utility forecasts
- Appendix A provides a more detailed discussion of state and regional GHG initiatives. Collectively, these initiatives suggest that momentum is building toward federal GHG action

3. Discussion of Key Assumptions

A. Federal GHG Legislation Is Increasingly Likely

Congressional action in the form of cap-and-trade or clean energy standards is only one avenue in an increasingly dynamic and complex web of activities that could result in internalizing a portion of the costs associated with emissions of greenhouse gases from the electric sector. The states, the federal courts, and federal agencies are also grappling with the complex issues associated with climate change. Many efforts are proceeding simultaneously.

Nonetheless, we believe that a federal cap-and-trade program for GHGs is the most likely policy outcome, as it enables the reduction of significant amounts of GHGs while allowing those reductions to come from sources that can mitigate their emissions at the least cost. Several cap-and-trade proposals have been taken up by Congress in the past few years, though none yet have been passed by both houses. (More discussion of this topic is provided in Section 5 of this report.)

We further believe that federal action will occur in the near-term. This 2012 CO_2 price forecast assumes that cap-and-trade legislation will be passed by Congress in the next five, and the resultant allowance trading program will take effect in 2020, prompted by one or more of the following factors:

- technological opportunity;
- a patchwork of state policies to achieve state emission targets for 2020 spurring industry demands for federal action;
- a Supreme Court decision to allow nuisance lawsuits to go ahead, resulting in a financial threat to energy companies; and
- increasingly compelling evidence of climate change.

Given the interest and initiatives on climate change policies in states throughout the nation, a lack of federal action will result in a hodgepodge of state policies. This scenario is a challenge for any company that seeks to make investments in existing, modified, or new power plants. Historically, this pattern of states and regions leading with initiatives that are eventually superseded at a national level is common for energy and environmental policy in the US. It seems likely that this will be the dynamic that ultimately leads to federal action on greenhouse gases, as well.

B. State and Regional Initiatives Building toward Federal Action

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to postpone and wait for federal action, are pursuing policies specifically because of the lack of federal legislation. These policies are described below, and are discussed in more detail in Appendix A of this report.

Cap and Trade Programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [2]

Under the Regional Greenhouse Gas Initiative (RGGI), ten Northeast and Mid-Atlantic states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.

Meanwhile, California's Global Warming Solutions Act (AB 32) has created the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS). The first compliance period for California's cap-and-trade program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and

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[2] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.

natural gas facilities emitting at least 25,000 metric tons of CO_2e per year. The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015.

State GHG Reduction Laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[3] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a combination of federal, regional, and state-level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[4] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[5]

Renewable Portfolio Standards & Other Initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

Currently, 29 U.S. states have renewable portfolio standards. Eight others have renewable portfolio goals. In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories, greenhouse gas registries, climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI (requiring specific emissions reductions from power plants in the state), and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

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[3] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan

[4] Minnesota Statutes 2008 § 216B.241

[5] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

4. Marginal Abatement Costs and Technologies

This chapter presents key data related to marginal abatement costs for CO_2, which were reviewed by Synapse in developing its estimates of the future price of CO_2 emissions.

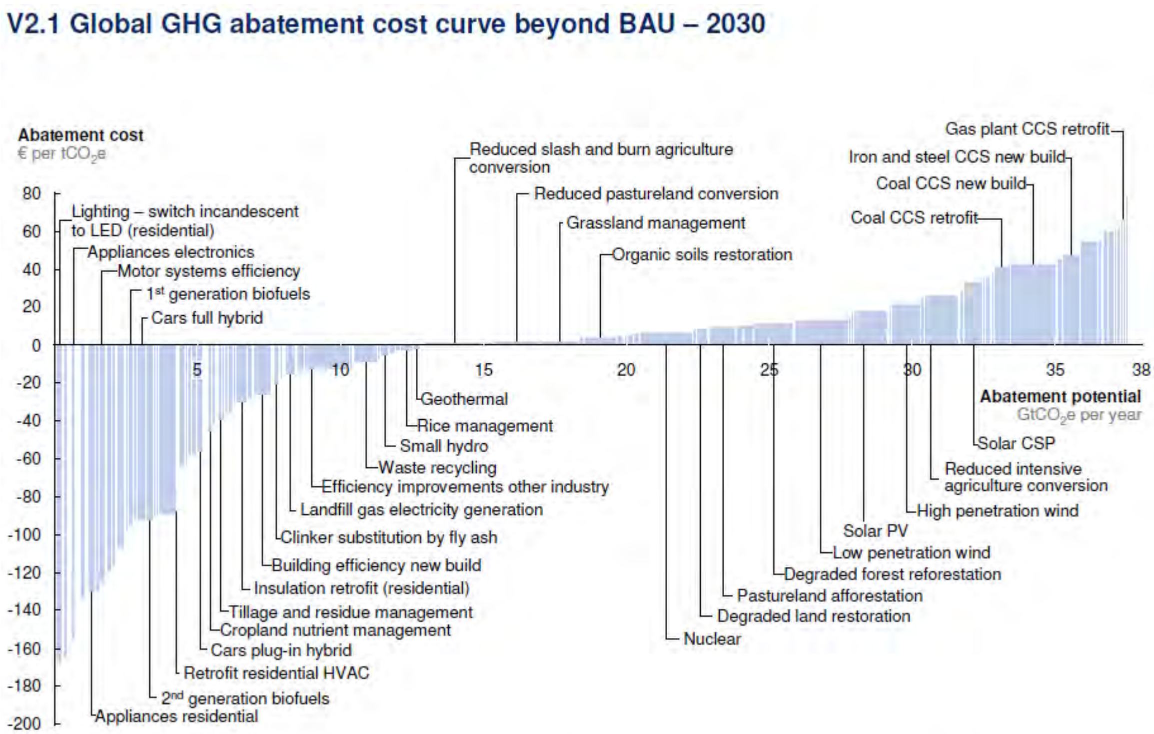
The long-run marginal abatement cost for CO_2 represents the cost of the control technologies necessary for the last (or most expensive) unit of emissions reduction required to comply with regulations. This cost depends on emission reduction goals: lower emissions reduction targets can be met by lower-cost technologies, while more stringent targets will require additional reduction technologies that are implemented at higher costs. The Copenhagen Agreement, drafted at the 15th session of the Conference of the Parties to the United Nations Framework Convention on Climate Change in 2009, recognizes the scientific view that in order to prevent the more drastic effects of climate change, the increase in global temperature should be limited to no more than 2° Celsius. Atmospheric concentrations of CO_2 would need to be stabilized at 450 ppm in order to limit the global temperature increase to no more than 2°C.[6]

In recent years, there have been several analyses of technologies that would contribute to emission reductions consistent with an increase in temperature of no more than 2°C. McKinsey & Company examined these technologies in a 2010 report entitled *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. The CO_2 mitigation options identified by McKinsey and the costs of those options are shown in Figure 1. Global mitigation options are ordered from least expensive to most expensive, and the width of each bar represents the amount of mitigation likely at these costs. The chart represents a marginal abatement cost price curve, where cost of abatement is shown on the y-axis and cumulative metric tonnes of GHG reductions are shown on the x-axis. It is likely that the lowest cost reductions will be implemented first, but as reduction targets become more stringent and low-cost options are saturated, the cost of abatement technologies is likely to increase.

The expected CO_2 price at any given time is the marginal abatement cost, or the cost of the most expensive mitigation option or technology that is required to meet a specific mitigation target. The chart below provides a useful reference to the types of options and technologies that might be employed at specific CO_2 prices.

[6] IPCC, 2007: Summary for Policymakers. In: *Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* [B. Metz, O.R. Davidson, P.R. Bosch, R. Dave, L.A. Meyer (eds)], Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Figure 1: Marginal Abatement Technologies and Associated Costs for the Year 2030.[7]



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €80 per tCO_2e if each lever was pursued aggressively. It is not a forecast of what role different abatement measures and technologies will play.
Source: Global GHG Abatement Cost Curve v2.1

As shown in Figure 1, technologies for carbon mitigation that are available to the electric sector include those related to energy efficiency, nuclear power, renewable energy, and carbon capture and storage (CCS) for fossil-fired generating resources. McKinsey estimates CCS technologies to cost 50-60 €/metric tonne (2005€). Converted into current dollars, this is equivalent to $65 to $85/short ton ($71.5 to $93.5/metric tonne, 2012$). According to the International Energy Agency (IEA), “in order to reach the goal of stabilizing global emissions at 450 ppm by 2050, CCS will be necessary.”[8] Thus, it is reasonable to expect that a CO_2 allowance price will rise to $65/short ton ($71.5/metric tonne) or higher under a GHG policy designed to limit the global temperature increase to no more than 2°C. However, if significant reductions could be accomplished with CCS at the high $65-$85/short ton CO_2 range, we would not expect CO_2 mitigation prices to significantly exceed the top of that range.

5. Analyses of Major Climate Change Bills

This chapter presents key data related to analyses of major climate change bills proposed in Congress over the past few years, which were reviewed by Synapse in developing its estimates of

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[7] McKinsey & Company. *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.* 2010. Page 8.
[8] International Energy Agency. *Technology Roadmap: Carbon Capture and Storage*. 2009. Page 4.

the future price of CO_2 emissions. Because we expect that a federal cap and allowance trading program will ultimately be adopted, analyses of these proposals offer some of the most relevant estimates of costs associated with greenhouse gas emissions under a variety of regulatory scenarios. It is not possible to compare the results of all of these analyses directly, however, because the specific models and the key assumptions vary.

A. Cap-and-Trade Proposals

In the past decade, the expectation has been that action on climate change policy will occur at the Congressional level. Legislative proposals have largely taken the form of cap-and-trade programs, which would reduce greenhouse gas emissions through a federal cap, and would allow trading of allowances to promote reductions in GHGs where they are most economic. Legislative proposals and President Obama's stated target aim to reduce greenhouse gas emissions by up to 80% from current levels by 2050.

Comprehensive climate legislation was passed in the House in the 111th Congress in the form of the American Clean Energy and Security Act of 2009 (ACES, also known as Waxman-Markey and HR 2454); however, the Senate ultimately did not take up climate legislation in that session. HR 2454 was a cap-and-trade program that would have required a 17% reduction in emissions from 2005 levels by 2020, and an 83% reduction by 2050. It was approved by the House of Representatives in June, 2009, but the Senate bill, known as the American Power Act of 2010 (APA, also known as Kerry-Lieberman), never came to a vote.

Figure 2, below, shows the results of EIA and EPA analyses of HR 2454 and APA. The chart shows the forecasted allowance prices in the central scenarios, as well as a range of sensitivities.

Figure 2: Greenhouse gas allowance price projections for HR 2454 and APA 2010

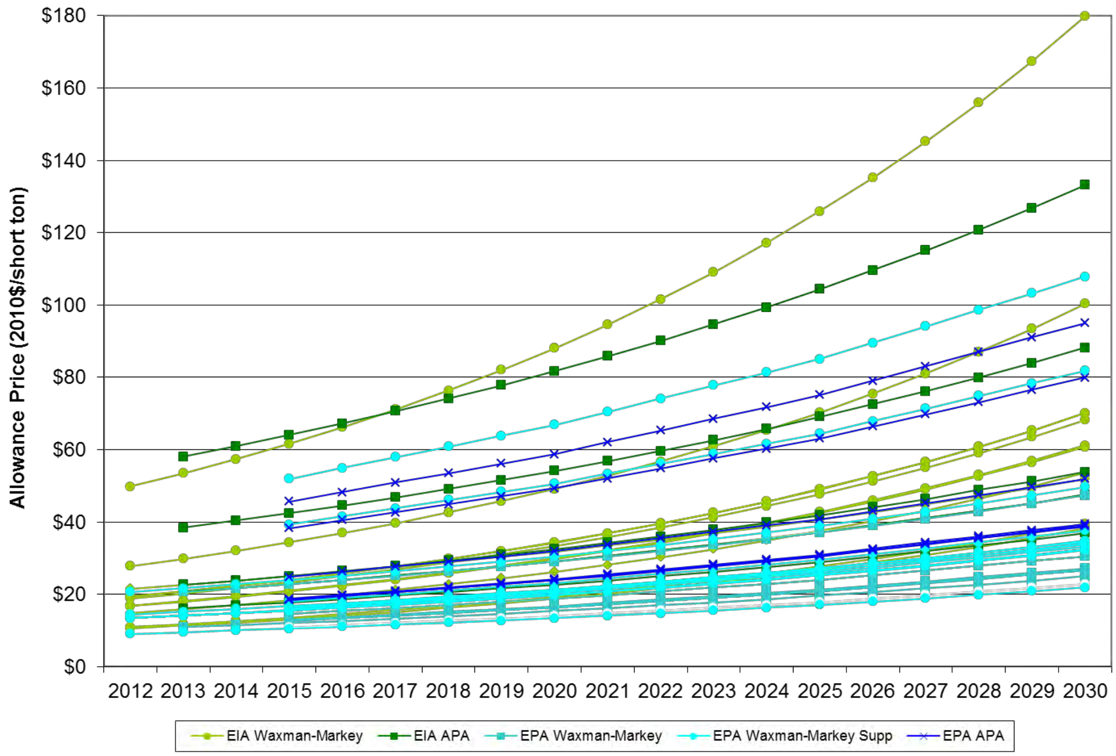
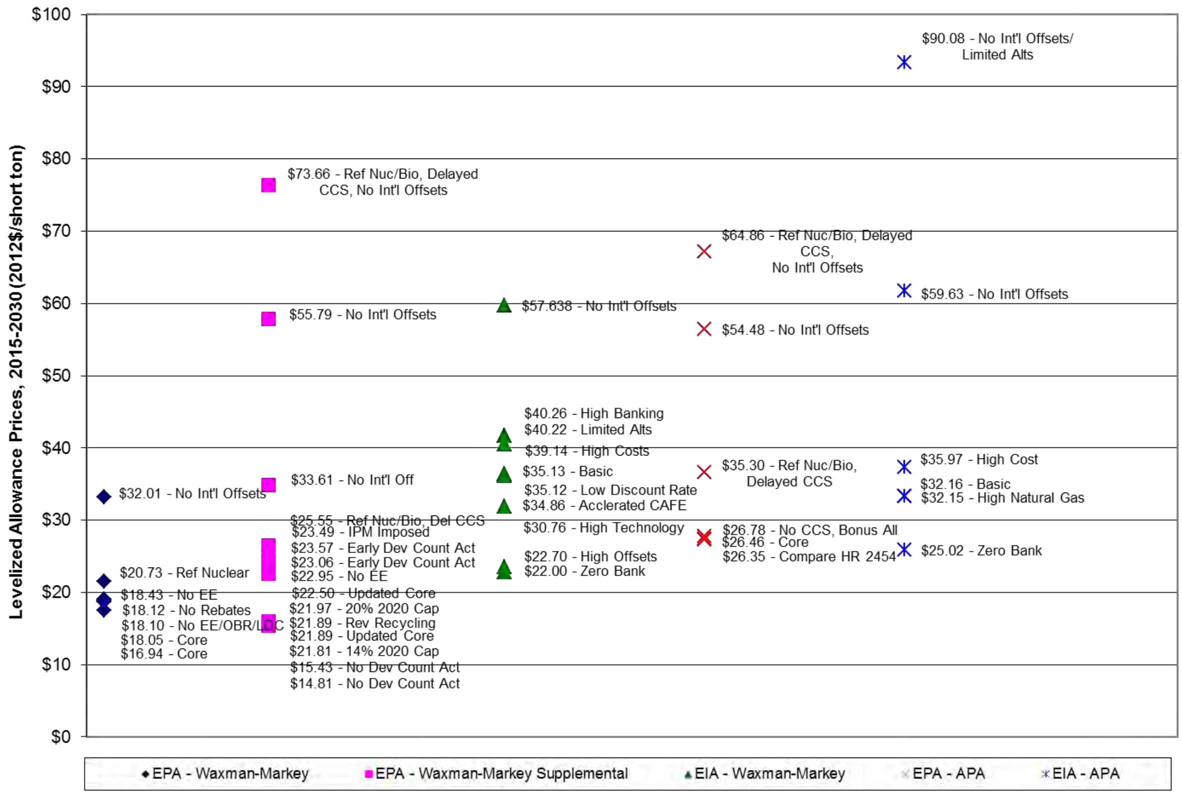


Figure 3, below, show these values as levelized prices for the time period 2015 to 2030.[9]

[9] Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

Figure 3: Greenhouse gas allowance price projections for HR 2454 and APA 2010 - levelized 2015-2030

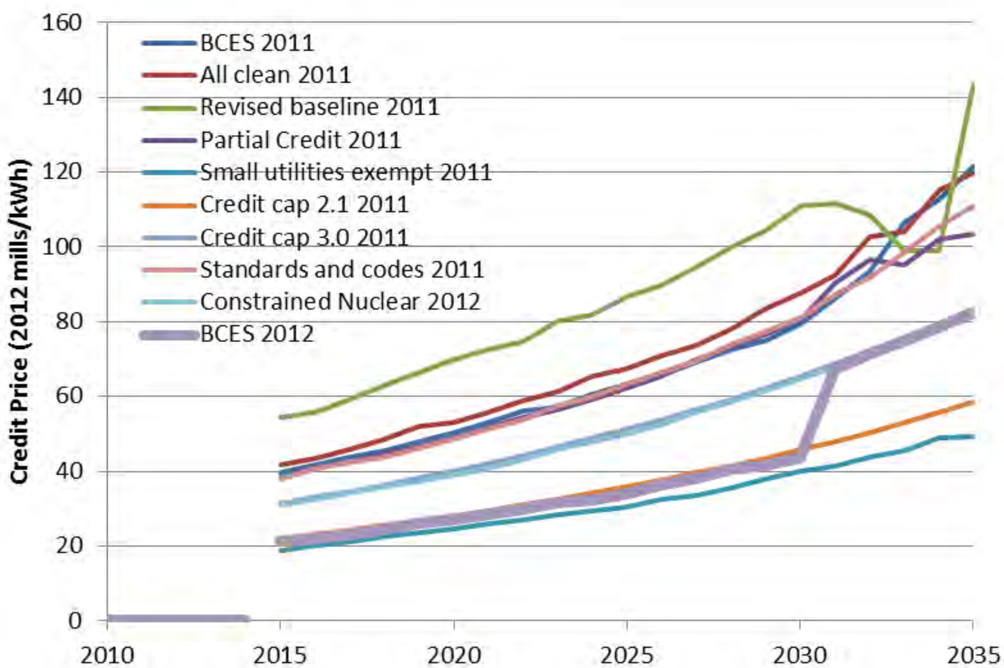


B. Clean Energy Standard

The 112th Congress chose not to revisit legislation establishing an economy-wide emissions cap, and instead focused on policies aimed at fostering technology innovation and developing renewable energy or clean energy standards. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S.2146), under which larger utilities would be required to meet a percentage of their sales with electric generation from sources that produce fewer greenhouse gas emissions than a conventional coal-fired power plant. All generation from wind, solar, geothermal, biomass, municipal solid waste, and landfill gas would earn a full CES credit, and new hydroelectric and nuclear facilities would also earn the credit. Lower-carbon fossil facilities, such as natural gas and coal with carbon capture, would earn partial credits based on their CO_2 emissions. Generation owners would be required to hold credits equivalent to 24% of their sales beginning in 2015, and the CES requirement rises over time to 84% by 2035, creating demand for renewable energy and low-emissions technologies. The credits generated by these clean technologies would be tradable and have a value that would change depending on how costly the policy is to achieve. The Clean Energy Standard would apply to utilities with sales greater than 2 million MWh, and expand to include those with sales greater than 1 million MWh by 2025.

The EIA conducted analyses of a potential Clean Energy Standard in both 2011 and 2012.[10,11] All of these cases result in some level of increase in nuclear, gas, and renewable generation, typically at the expense of coal. The exact generation mix, as well as the resulting reduction in emissions, is highly dependent on both the technology costs and policy design. The resulting CES Credit prices (Figure 4) vary widely, from 25 to 70 mills/kWh in 2020,[12] rising to 47 to 138 mills/kWh in 2035. The credit cap cases show a smaller rise in credit prices. When credit prices are capped at a specific value, clean energy deployment and emissions abatement is reduced.

Figure 4: CES Credit Prices in EIA Analyses of a US Clean Energy Standard



An effective CO_2 allowance price can be calculated based on the fact that this policy gives existing gas combined cycle units 0.48 credits and existing coal units zero credits, and the emissions from an average gas unit are about 0.57 tCO_2/MWh and from an average coal unit 1.125 tCO_2/MWh.[13] For the BCES 2012 case, this results in effective prices increasing from \$18.4/tCO_2 in 2015 to \$71.4/tCO_2 in 2035.

[10] US EIA. 2011. Analysis of Impacts of a Clean Energy Standard as requested by Chairman Bingaman. http://www.eia.gov/analysis/requests/ces_bingaman/.
[11] US EIA. 2012. Analysis of the Clean Energy Standard Act of 2012. http://www.eia.gov/analysis/requests/bces12/.
[12] A mill is one one-hundredth of a cent. Therefore, these CES prices in 2020 represent costs of 0.25 to 0.70 ¢/kWh, or \$2.5 to \$7/MWh.
[13] EPA Air Emissions Overview, Available at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.htm

6. Key Factors Affecting Allowance Price Projections

Dozens of analyses over the past several years have shown that there are a number of factors that affect projections of allowance prices under federal greenhouse gas regulation. Some of these factors derive from the details of policy design, while others pertain to the context in which a policy would be implemented.

Factors in a forecast include: the base case emissions forecast; the reduction targets in each proposal; whether complementary policies such as aggressive investments in energy efficiency and renewable energy are implemented independent of the emissions allowance market; the policy implementation timeline; program flexibility regarding emissions offsets (perhaps including international offsets) and allowance banking; assumptions about technological progress; the presence or absence of a “safety valve” price; and emissions co-benefits. Figures 6 and 7 show the very significant ranges in emissions and allowance prices for the Waxman-Markey and APA federal cap-and-trade policies, as well as several associated sensitivities, including assumptions on banking, international offsets, technology cost and progress, and gas supply.

Figure 5: GHG Emissions in Waxman-Markey and APA policies and sensitivities

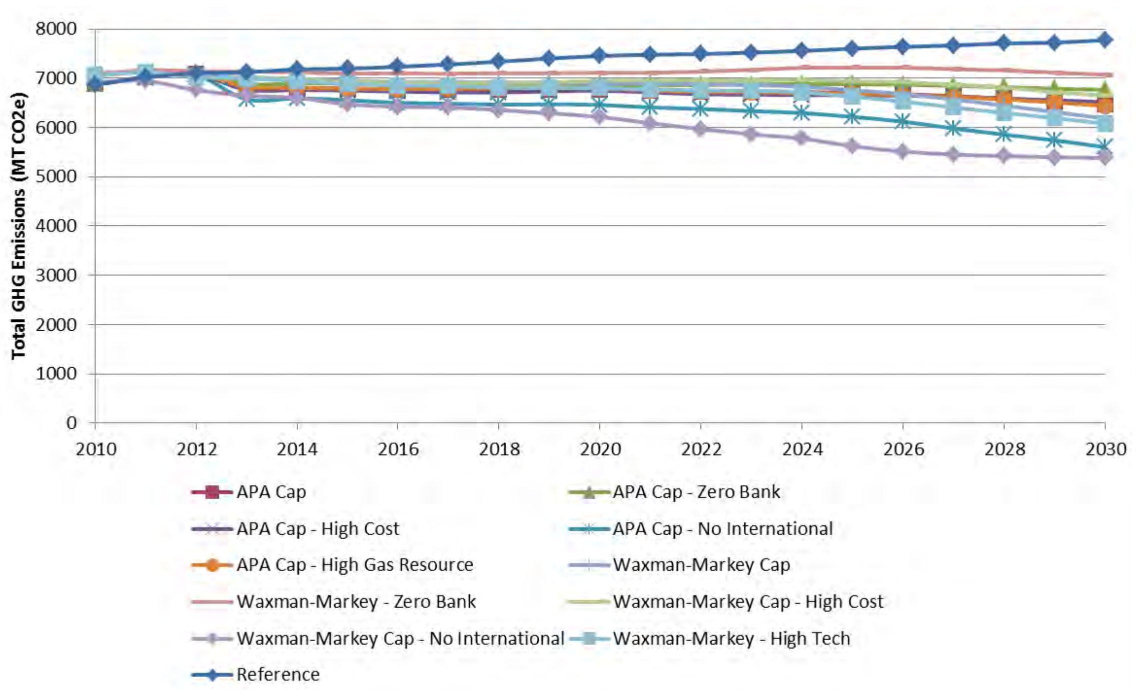
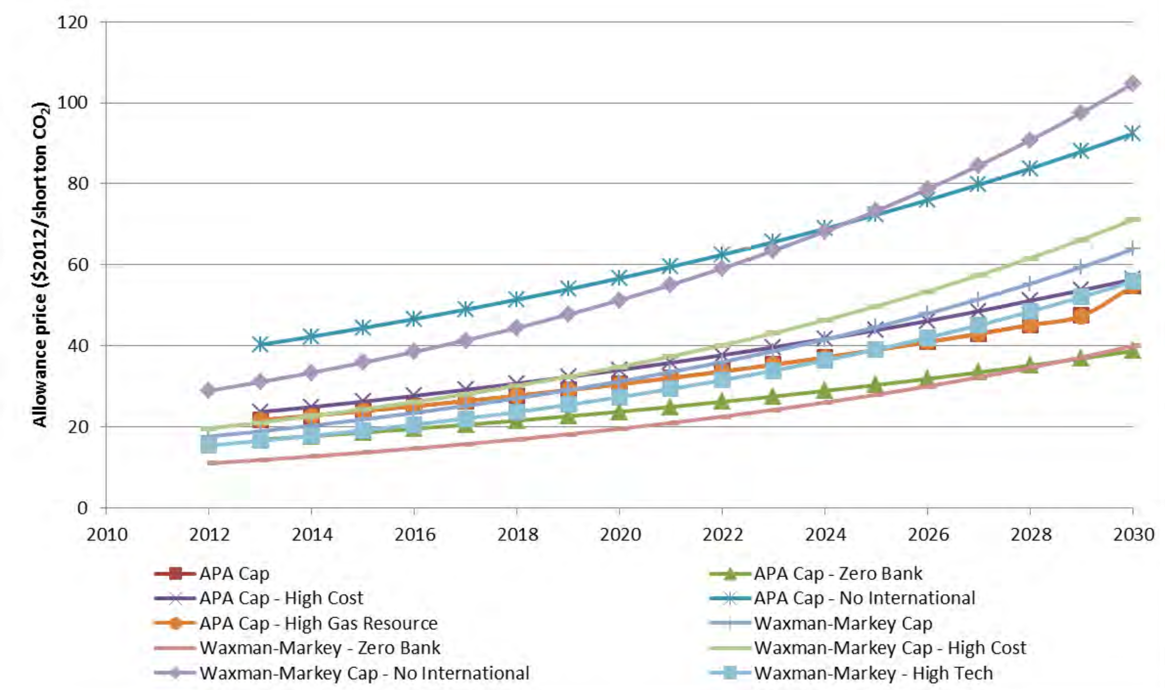


Figure 6: Allowance prices in ACES and APA policies and sensitivities



A. Assessing the Potential Impact of a Natural Gas Supply Increase

The recent shale gas boom has put substantial downward pressure on natural gas prices. Several factors could influence future gas prices, including the estimated ultimate recovery per well as well as concerns about the environmental impacts of hydraulic fracturing.[14] The impact of higher or lower gas prices on carbon prices is uncertain. In the near term, lower natural gas prices are likely to make emissions mitigation in the electric sector less expensive, as gas power plants can at times be a cost-effective replacement for aging coal plants. Conversely, as marginal electricity prices are frequently set by natural gas plants, lower gas prices will contribute to lower electricity prices, potentially increasing electricity consumption and associated emissions. Lower electricity prices also make it more difficult for renewable technologies with even lower emissions than gas to compete in electricity markets.

In 2010, Resources for the Future used a version of the EIA's National Energy Modeling System (NEMS) energy model to test effects of increased gas supply from shale gas. Under a moderate climate policy, the high gas scenario decreased the 2030 allowance price by less than 1%, from $61.1 to $60.8 per short ton CO_2 ($67.26 to $66.83 per metric tonne).[15] The EIA showed similar results in its analysis of the American Power Act; increased gas supply decreased the 2030 allowance price by less than 0.1%, from $49.80 to $49.78 per short ton CO_2 ($54.78 to $54.76 per

[14] EIA (2012) "Projected natural gas prices depend on shale gas resource economics" http://www.eia.gov/todayinenergy/detail.cfm?id=7710

[15] Brown et al (2010). "Abundant Shale Gas Resources: Some Implications for Energy Policy". Available at: http://www.rff.org/RFF/Documents/RFF-BCK-Brownetal-ShaleGas.pdf

metric tonne).[16] In the policies studied by EIA and RFF, the result of an increased gas supply amounted to an inconsequential reduction in CO_2 prices. At this point it appears that, while a large shale gas resource may change how each policy is met, it is not a significant driver in the CO_2 cost that utilities should use for planning. Other studies are ongoing to explore these issues further.[17]

7. The US Interagency Social Cost of Carbon

In 2010, the U.S. government began to use "social cost of carbon" values to account for the damages resulting from climate change.[18] Four values for the social cost of carbon were initially provided by the Interagency Working Group on the Social Cost of Carbon, a group composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others. This group was tasked with the development of a consistent value for the social benefits of climate change abatement. These values, $4.5, $19.1, $31.8, and $59.1 per short ton CO_2 ($5, $21, $35, and $65 per metric tonne, in 2007 dollars), accounted for three discount rates and one estimate of the high cost tail-end of the distribution of impacts. As of May 2012, these estimates have been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[19]

These values are the result of analysis of the DICE, PAGE, and FUND integrated assessment models. The combination of complex climate and economic systems with these reduced-form integrated assessment models leads to substantial uncertainties. In a 2012 paper, Ackerman and Stanton[20] modified assumptions used by the Interagency Working Group related to climate sensitivity, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Despite limitations in the calculations for the social cost of carbon stemming from the choice of socio-economic scenarios, modeling of the physical climate system, and projecting damages hundreds of years into the future, this multi-agency effort represents an initial attempt at incorporating consistent values for the benefits associated with CO_2 abatement in federal policy.

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[16] EIA (2010) "Energy Market and Economic Impacts of the American Power Act of 2010". Available at: http://www.eia.gov/oiaf/servicerpt/kgl/index.html

[17] The Energy Modeling Forum will evaluate carbon constraints under cases of reference and high case supply levels in the EMF 26 study, which began in late 2011 and is ongoing (see http://emf.stanford.edu/research/emf_26/)

[18] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

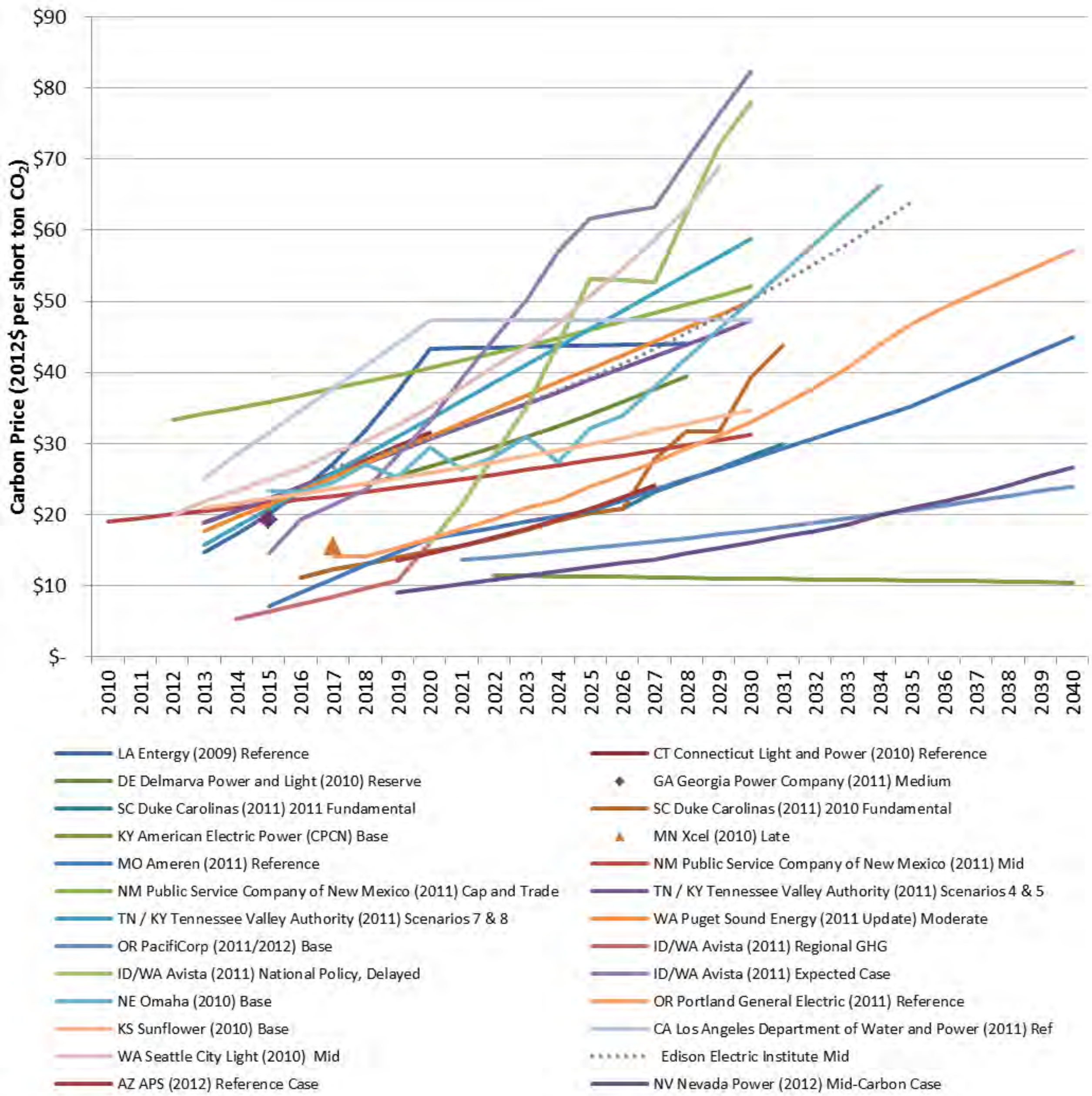
[19] Robert E. Kopp and Bryan K. Mignone (2012). The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15

[20] Frank Ackerman and Elizabeth A. Stanton (2012). Climate Risks and Carbon Prices: Revising the Social Cost of Carbon. Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10

8. CO_2 Price Forecasts in Utility IRPs

A number of electric companies include projections of costs associated with greenhouse gas emissions in their resource planning procedures. Figure 7, below, summarizes the central values of publicly available forecasts used by utilities in resource planning over the past two years.

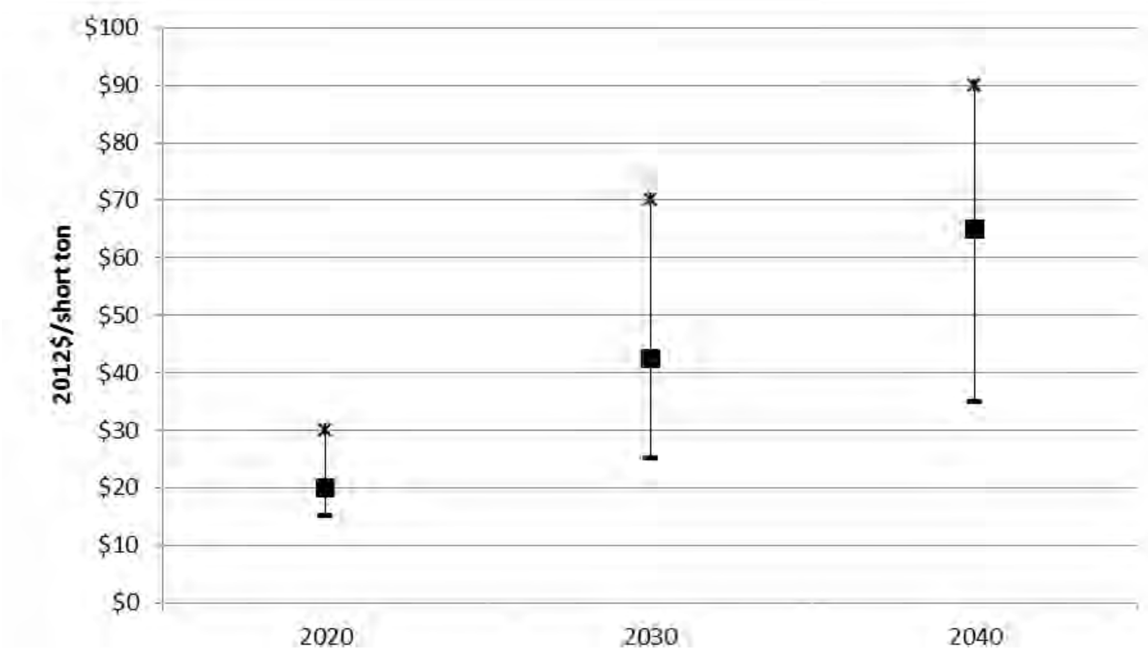
Figure 7: Utility Mid Case CO_2 Price Forecasts



9. Recommended 2012 CO_2 Price Forecast

Based on analyses of the sources described in Sections 4 through 8, above, and relying on its own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2020 to 2040. Figure 8 shows the range covered by the Synapse forecasts in three key years, 2020, 2030, and 2040. These forecasts share the common assumption that a federal cap-and-trade policy will be passed sometime within the next five years, and will go into effect in 2020. All annual allowance prices and levelized values are reported in 2012 dollars per short ton of carbon dioxide.[21]

Figure 8: Synapse 2012 Forecast Values



Each of the forecasts shown in Figure 9 represents a different appetite for reducing carbon, as described below.

- The Low case forecast starts at $15/ton in 2020, and increases to approximately $35/ton in 2040, representing a $23/ton levelized price over the period 2020-2040.[22] This forecast represents a scenario in which Congress begins regulation of greenhouse gas emissions slowly—for example, by including a modest emissions cap, a safety valve price, or significant offset flexibility. This price forecast could also be realized through a series of

[21] All values in the Synapse Forecast are presented in 2012 dollars. Results from EIA and EPA modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis, and available at: http://www.bea.gov/national/nipaweb/SelectTable.asp Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year. Consistent with EIA and EPA modeling analyses, a 5% real discount rate was used in all levelization calculations.

[22] Throughout this report, CO2 allowance prices are presented in $2012 per short ton CO2, except in reference to a few original sources, where alternate units are clearly labeled. Results from other modeling analyses were converted to 2012 dollars using price deflators taken from the US Bureau of Economic Analysis. Because data were not available for 2012 in its entirety, values used for conversion were taken from Q2 of each year.

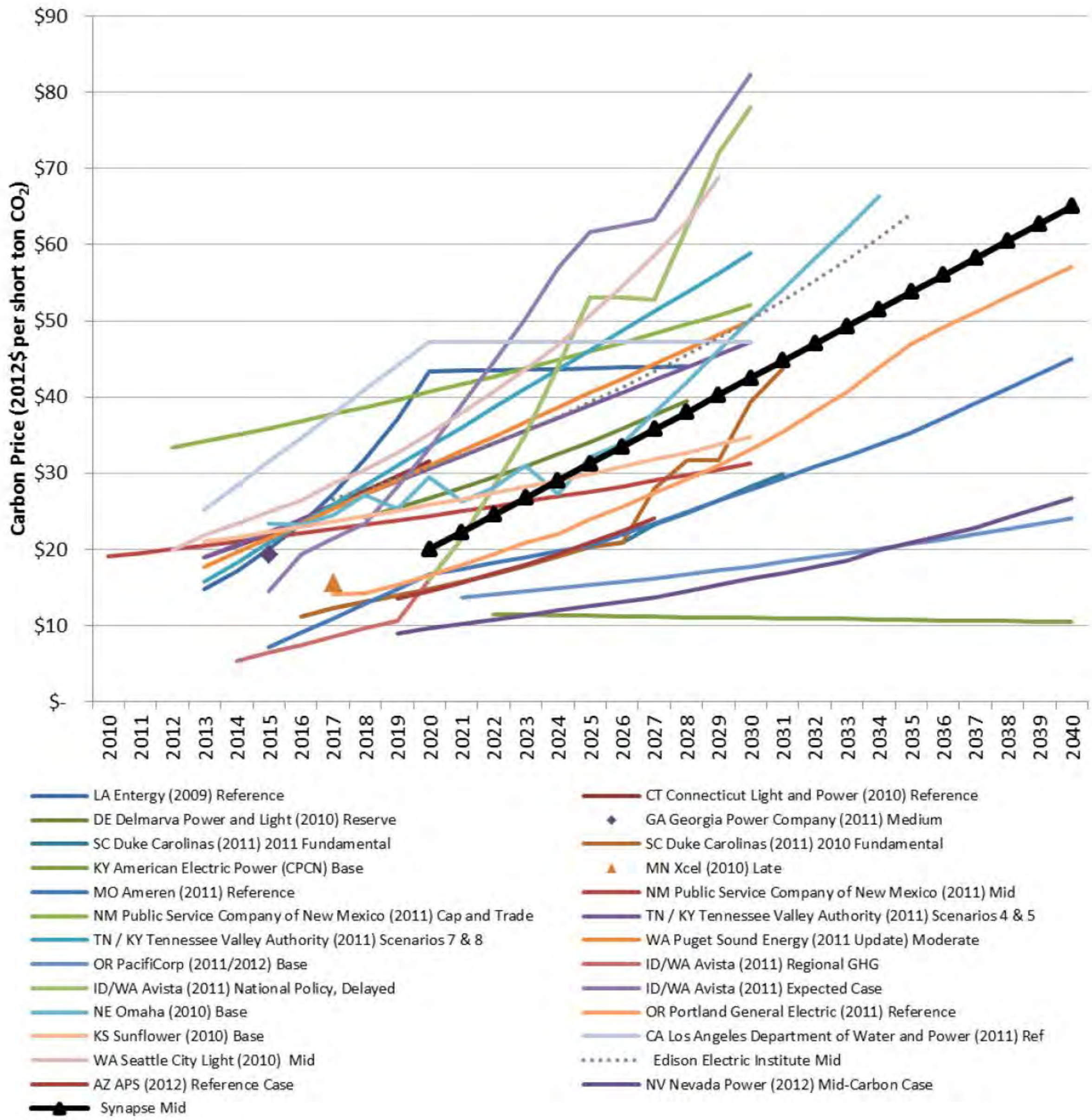
complementary policies, such as an aggressive federal Renewable Portfolio Standard, substantial energy efficiency investment, and/or more stringent automobile CAFE mileage standards (in an economy-wide regulation scenario). Such complementary policies would lead directly to a reduction in CO_2 emissions independent of federal cap-and-trade, and would thus lower the expected allowance prices associated with the achievement of any particular federally mandated goal.

- The Mid case forecast starts at $20/ton in 2020, and increases to approximately $65/ton in 2040, representing a $39/ton levelized price over the period 2020-2040. This forecast represents a scenario in which a federal cap-and-trade program is implemented with significant but reasonably achievable goals, likely in combination with some level of complementary policies to give some flexibility in meeting the reduction goals. These complementary policies would include renewables, energy efficiency, and transportation standards, as well as some level of allowance banking and offsets. Also assumed in the Mid case is some degree of technological learning, i.e. assuming that prices for emissions reductions technologies will decline as greater efficiencies are realized in their design and manufacture and as new technologies become available.
- The High case forecast starts at $30/ton in 2020, and increases to approximately $90/ton in 2040, representing a $59/ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

The following charts compare the Synapse Mid case against various utility estimates. Data on utility estimates was collected from a wide range of available public Integrated Resource Plans (IRP). We have excluded several IRP with zero carbon prices or IRP with no carbon price given, accounting for 9 of 65 collected.

Figure 9, below, shows 26 utility CO_2 price forecasts, with 2030 prices ranging from $10/t$CO_2$ to above $80/t$CO_2$. Due to the extended development period of many IRP, some of these forecasts may not accurately reflect very recent years; a NM Public Service forecast, for example, begins in 2010, when there was certainly not an economy-wide CO_2 price. Nevertheless, IRP do their best to represent accurate views of the future, in order to develop least-cost plans. The Synapse Mid forecast, beginning at $20/t$CO_2$ and rising to $65/t$CO_2$, lies solidly in the middle of the other forecasts shown here.

Figure 9: Synapse 2012 Mid forecast as compared to the reference cases of various U.S. utilities (2010-2012)[23]



23 Legend given here is common to all subsequent utility price forecast charts. While scenario names may change, colors are constant for a given utility.

Figure 10: Utility High forecasts compared to utility Mid forecasts

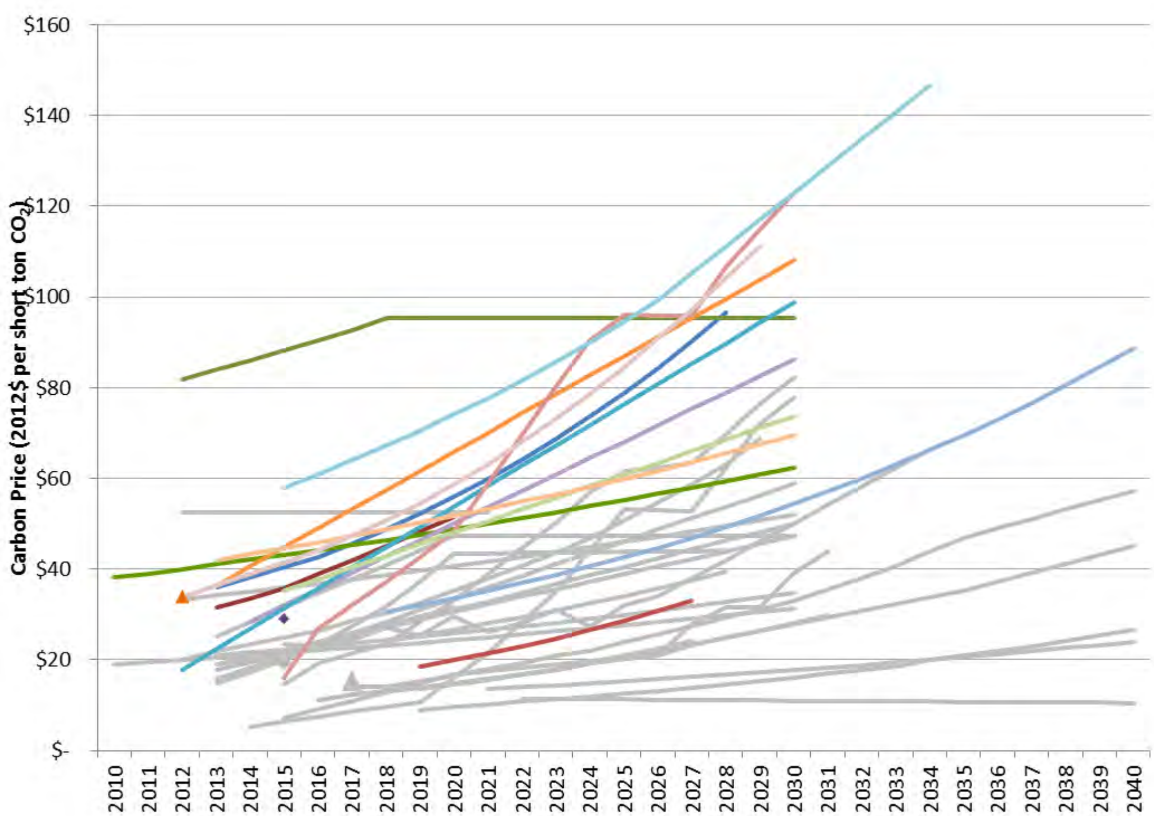


Figure 10, above, overlays the high case forecasts of many IRPs on top of the mid case forecasts (now shaded in grey). Not all IRP that provide mid-level forecasts also provide high forecasts. The high cases generally reflect a nearer-term policy start date, as well as a more rapid rate of increase in prices with time.

Figure 11: Utility High forecasts compared to utility Mid forecasts, with Synapse High case

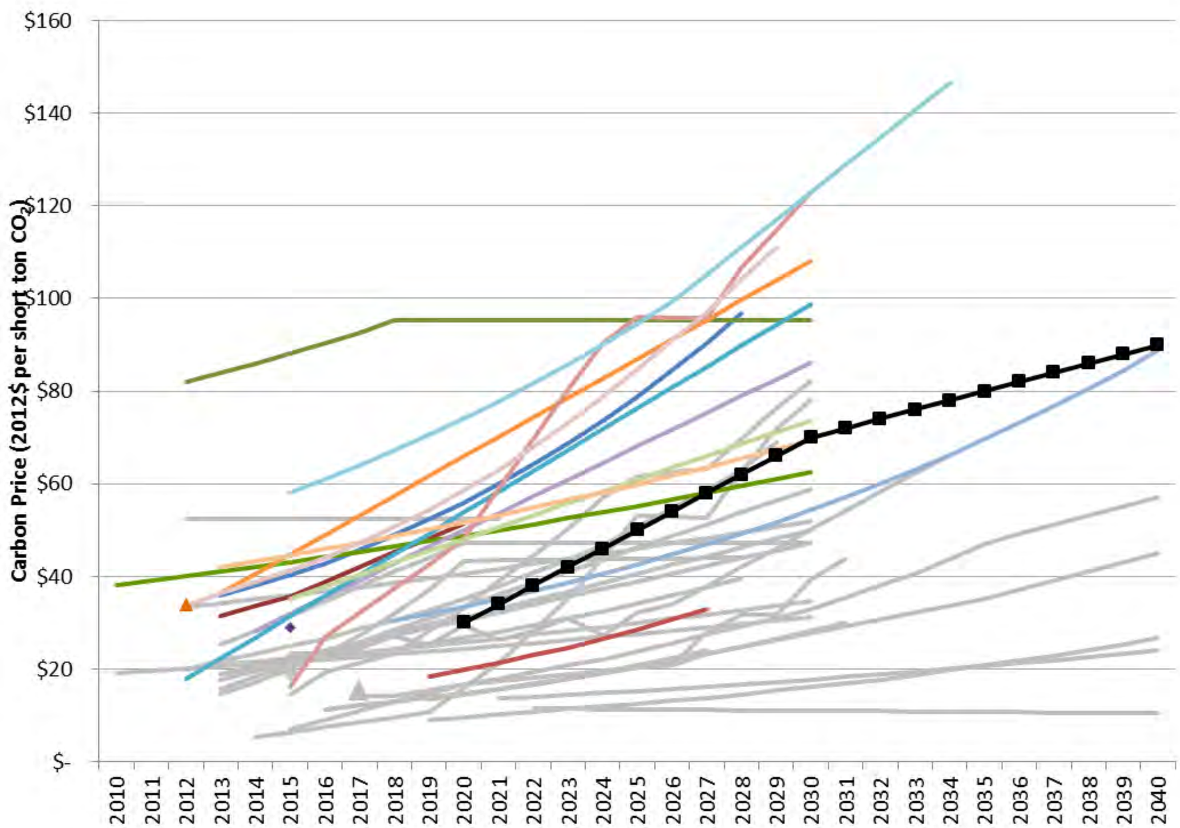


Figure 11 overlays the Synapse High case forecast on top of what is shown in Figure 10. The Synapse forecast starts later than most, and rises from $30/tCO_2$ to $90/tCO_2$ in 2040.

Figure 12: Utility Low and Mid forecasts

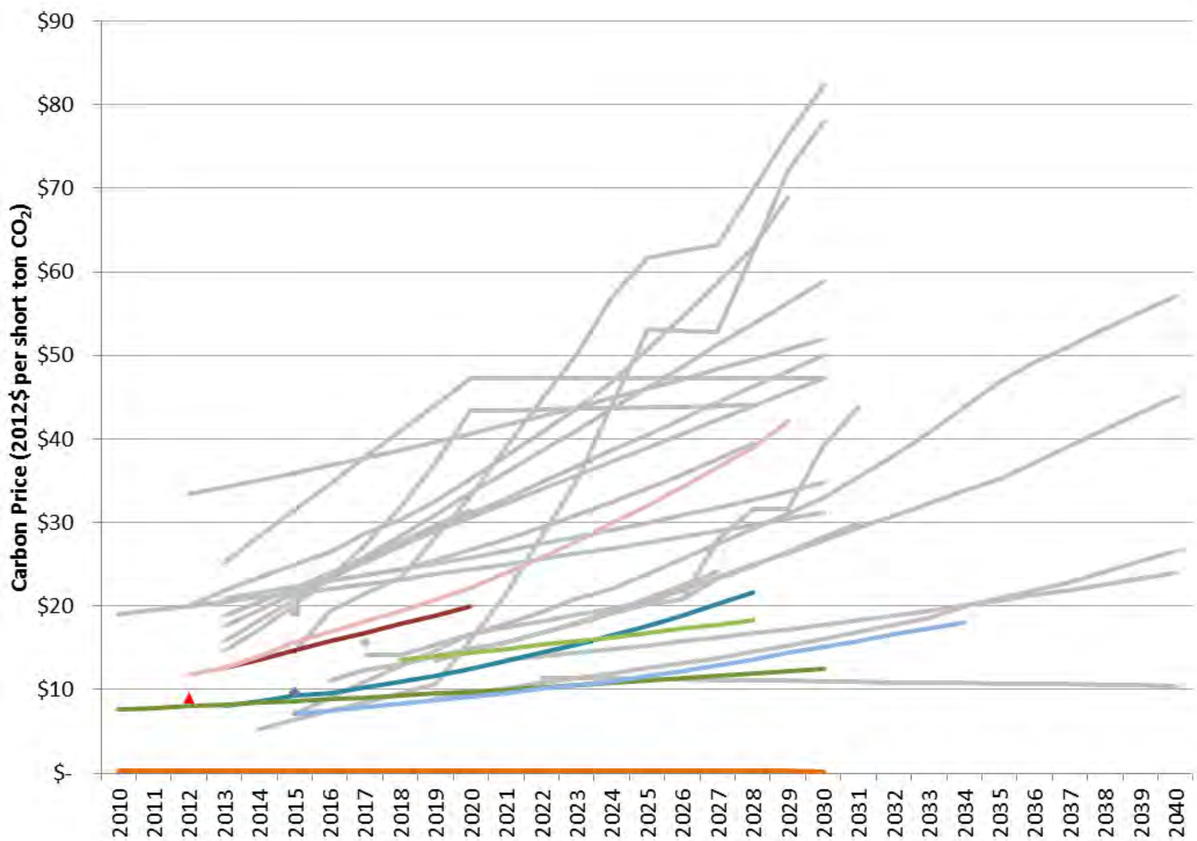


Figure 12, above, overlays the low forecasts of many IRP on top of the Mid case forecasts. The low forecasts both start at substantially lower values (occasionally at zero values), and rise at slower rates.

Figure 13: Synapse Low forecast compared to utility Low forecasts

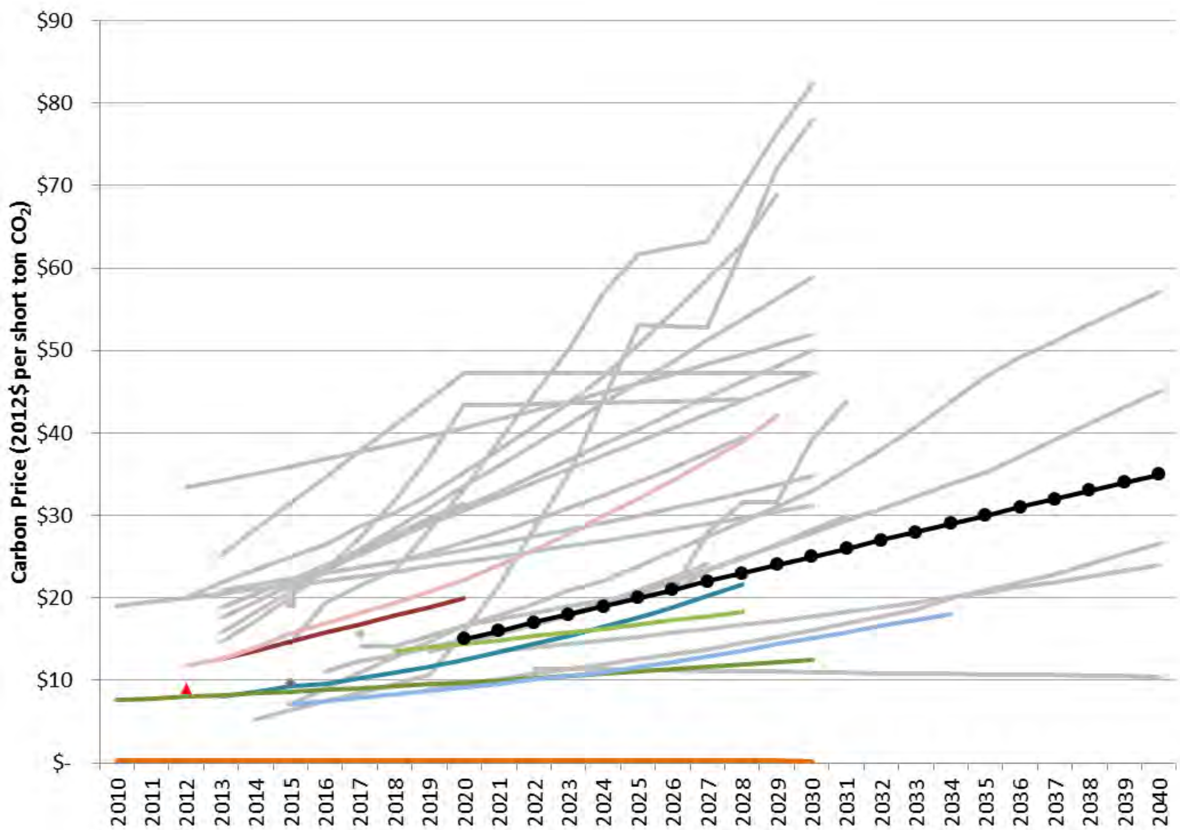


Figure 13 overlays the Synapse Low case forecast on top of IRP low case forecasts. The Synapse forecast starts later than most and rises from \$15/tCO_2 to \$35/tCO_2 in 2040.

The Synapse 2012 CO_2 price trajectories are shown in Figure 14 and

Table 1, below.

Figure 14: Synapse 2012 CO_2 Price Trajectories

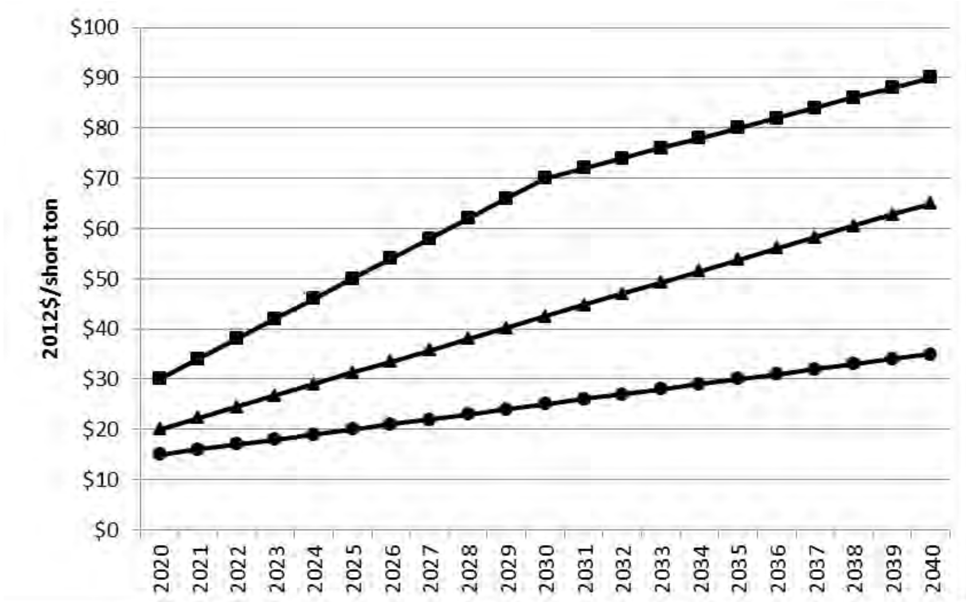


Table 1: Synapse 2012 CO_2 Allowance Price Projections (2012 dollars per short ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$30.00
2021	$16.00	$22.25	$34.00
2022	$17.00	$24.50	$38.00
2023	$18.00	$26.75	$42.00
2024	$19.00	$29.00	$46.00
2025	$20.00	$31.25	$50.00
2026	$21.00	$33.50	$54.00
2027	$22.00	$35.75	$58.00
2028	$23.00	$38.00	$62.00
2029	$24.00	$40.25	$66.00
2030	$25.00	$42.50	$70.00
2031	$26.00	$44.75	$72.00
2032	$27.00	$47.00	$74.00
2033	$28.00	$49.25	$76.00
2034	$29.00	$51.50	$78.00
2035	$30.00	$53.75	$80.00
2036	$31.00	$56.00	$82.00
2037	$32.00	$58.25	$84.00
2038	$33.00	$60.50	$86.00
2039	$34.00	$62.75	$88.00
2040	$35.00	$65.00	$90.00
Levelized	$23.24	$38.54	$59.38

The Synapse projections represent a range of possible future costs. These recommended price trajectories will be useful for testing long-term investment decisions in electric sector resource planning. There will certainly be variability and volatility in prices caused by supply and demand dynamics, as there is with other cost drivers. Nonetheless, these projections represent a useful price range for resource planning and policy analysis in the face of uncertainty.

Figure 15, below, shows Synapse's Low, Mid, and High forecasts compared to the full range of utility forecasts shown above.

Figure 15: Synapse forecasts compared to the range of utility forecasts

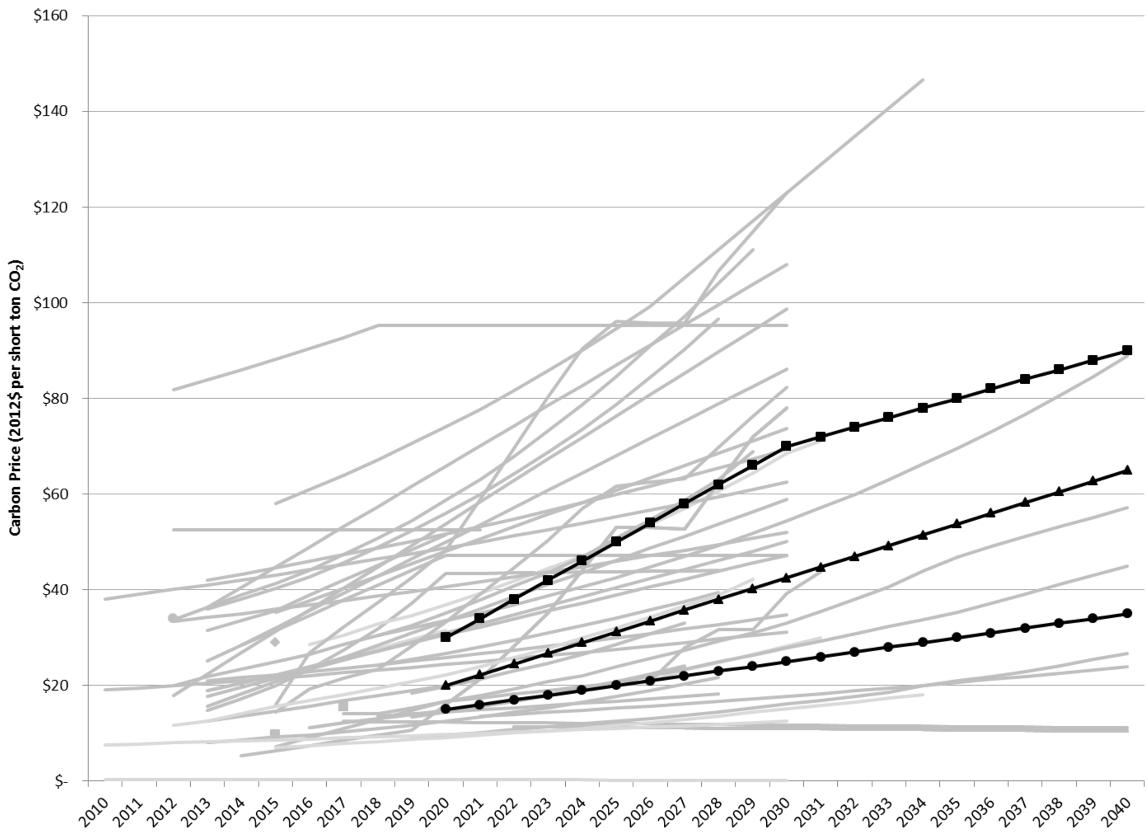
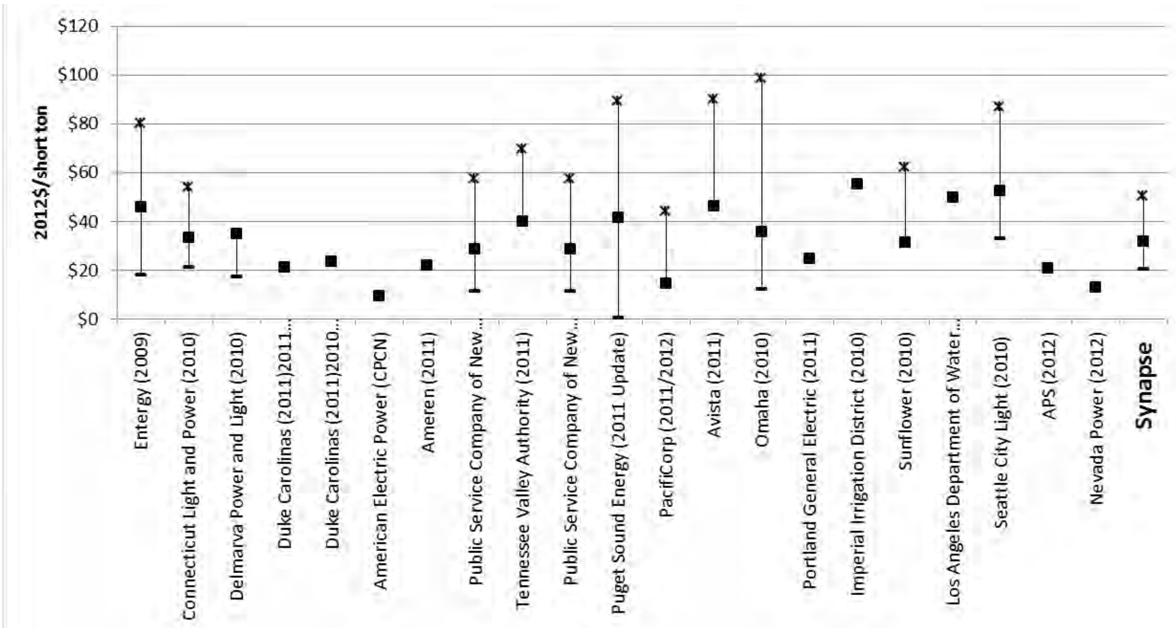


Figure 16, below, compares the levelized costs of Synapse's Low, Mid, and High cases against the levelized costs of utility estimates for 2020 through 2030, a period after the start and before the end of most forecasts. Levelizing between 2020 and 2030 results in different Synapse values than presented in Table 1, where forecasts were levelized between 2020 and 2040.

Figure 16: Levelized price of CO_2, 2020-2030, utilities and Synapse[24]



[24] All forecasts are levelized with a 5% discount rate based on CO_2 prices between 2020 and 2030. Forecasts with a price for only a single year excluded.

Appendix A: State and Regional GHG Initiatives

The states—individually and coordinating within regions—are leading the nation's policies to respond to the threat of climate change. In fact, several states, unwilling to postpone and wait for federal action, are pursuing policies specifically because of the lack of federal legislation.

This appendix provides a more thorough discussion of state and regional greenhouse gas (GHG) initiatives. Collectively, these initiatives suggest that momentum is building toward more comprehensive federal GHG action.

Cap and Trade Programs

The Northeast/Mid-Atlantic region and the state of California have developed, or are in the last stages of developing, greenhouse gas caps and allowance trading. [25]

Regional Greenhouse Gas Initiative: The Regional Greenhouse Gas Initiative (RGGI) is an effort of ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions, and is the first market-based CO_2 emissions reduction program in the United States. Participating states have agreed to a mandatory cap on CO_2 emissions from the power sector with the goal of achieving a ten percent reduction in these emissions from levels at the start of the program by 2018.[26] This is the first mandatory carbon trading program in the nation. Recently, allowance prices have been hitting the CO_2 price floor, as actual emissions are far below the budget of 188 mtons/year.

California: In 2006, the California Legislature passed the Global Warming Solutions Act (AB 32), which requires the state to reduce emissions of GHGs to 1990 levels by 2020. The California Air Resources Board (CARB) outlined more than a dozen measures to reduce carbon emissions to target levels in its 2008 *Scoping Plan*. Those measures include a renewable portfolio standard, a low carbon fuel standard, and a cap-and-trade program. Approximately 22.5% of the emissions reductions called for by AB 32 are estimated to occur under the cap-and-trade program. California will have the world's second largest carbon market, after the European Union's Emissions Trading System (EU ETS).

The first compliance period for the program will begin on January 1, 2013, and will cover electricity generators, carbon dioxide suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 25,000 metric tons of CO_2e per year. The second compliance period will run from 2015-2017, and the third compliance period will cover 2018-2020. During these periods, the cap-and-trade program will expand to cover suppliers of natural gas, distillate fuel oil, and liquefied petroleum gas if the combustion of their products would result in 25,000 metric tons of CO_2e or more.[27] The initial cap is set at 162.8 million metric tons of CO_2e and decreases by 2% annually through 2015. When additional sources are added, the cap increases to accommodate them, but then increases the percentage reductions in emissions to 3% in 2016, rising to 2.5% in 2020. The state plans to allocate the bulk of allowances for free in 2013, but will gradually auction

[25] The Midwest Greenhouse Gas Reduction Accord was developed in 2007. Though the agreement has not been formally suspended, the participating states are no longer pursuing it.

[26] The ten states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont. Information on the RGGI program, including history, important documents, and auction results is available on the RGGI Inc website at www.rggi.org

[27] §95812 (d)(1), page 48

an increasing number of allowances between 2013 and 2020. Banking[28] and offsets[29] are both allowed under the California program.

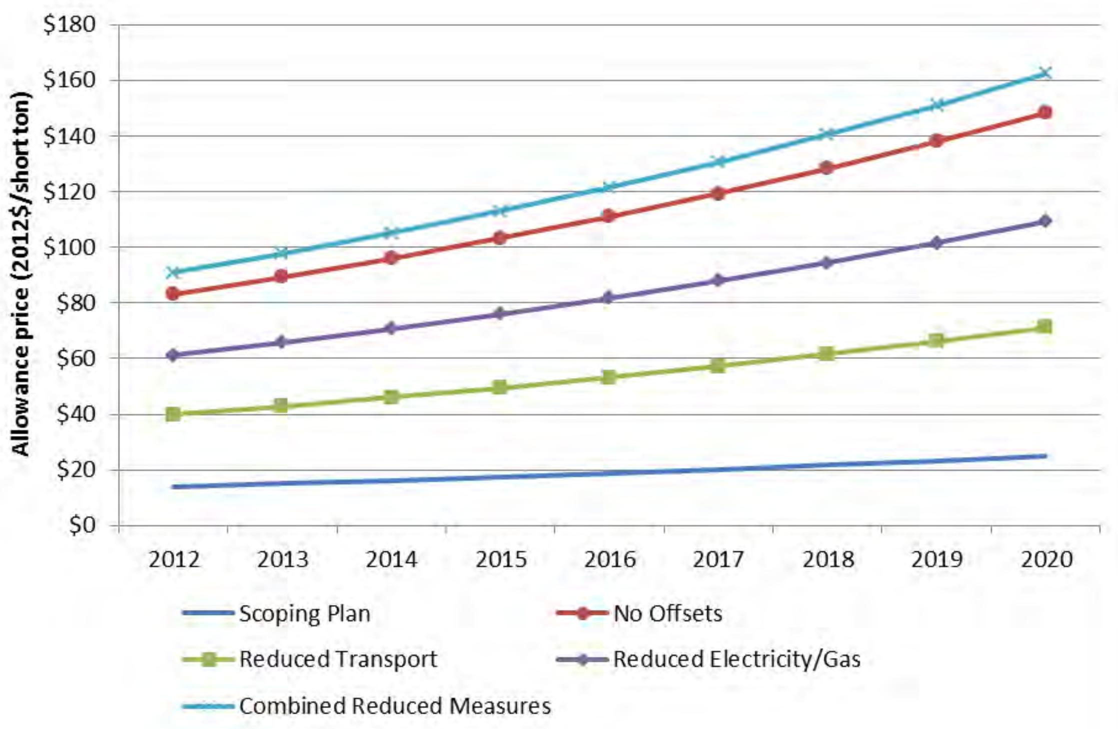
The state of California has set a floor price for allowances beginning at $9.1/short ton in 2013 ($10/metric tonne), and rising annually by 5% plus the rate of inflation.[30] In 2010 the Air Resources Board modeled the CO_2 allowance price trajectory that would enable reduction targets to be met under the following five cases:

1. Scoping Plan: Implements all of the measures contained in CARB's *Scoping Plan*
2. No Offsets: Does not allow offsets in the cap-and-trade program
3. Reduced Transport: Examines less effective implementation of the transportation-sector measures
4. Reduced Electricity/Gas: Examines less successful implementation of the electricity and natural gas measures
5. Combined Measures Reduced: Examines less successful implementation of transportation, electricity, and natural gas measures[31]

These five cases represent different scenarios of regulatory programs which, although different from the cap-and-trade program, can simultaneously help to achieve the goals of cap-and-trade. These regulatory measures are known as complementary policies. Figure 17, below, shows the allowance price trajectories associated with those five cases.

[28] §95922 (a), page 151
[29] §95973 (a)(2)(C), page 156
[30] §95911 (b)(6), page 129
[31] California Air Resources Board. *Updated Economic Analysis of California's Climate Change Scoping Plan: Staff Report to the Air Resources Board.* March 24, 2010. Page ES-6.

Figure 17: AB 32 Modeled Allowance Price Trajectories[32]



As shown in Figure 17, when the policies that are complementary to the cap-and-trade program are less effective, greater CO_2 reductions need to occur under the cap-and-trade program, and the allowance price is much higher. Similarly, the availability of offsets lowers the allowance price in the cap-and-trade program, as compliance with reduction targets can be met with offsets. This allows banking of allowances in the beginning of the program, which can keep allowance prices lower in later years.

California's first allowance auction is scheduled for November 14. A trial auction was completed on August 30, and more than 430 entities that will be regulated under the cap-and-trade program were invited to participate. CARB does not plan to release a settlement price, but on the date of the test auction, futures for December 2013 were trading at $14.77/short ton ($16.30/metric ton), and forward contracts had sold for $14.77 and $14.82/short ton ($16.25 and $16.30/metric ton).

State GHG Reduction Laws

Massachusetts: In 2008, the Massachusetts Global Warming Solutions Act was signed into law. In addition to the commitments to power sector emissions reductions associated with RGGI, this law committed Massachusetts to reduce statewide emissions to 10-25% below 1990 levels by 2020 and 80% below 1990 levels by 2050. Following the development of a comprehensive plan on steps to meet these goals, the 2020 target was set at 25% below 1990 levels.[33] Rather than put a price on carbon in the years before 2020, this plan will achieve a 25% reduction through a

[32] Id. Page 40.
[33] Massachusetts Clean Energy and Climate Plan for 2020, Available at: http://www.mass.gov/green/cleanenergyclimateplan

combination of federal, regional, and state level regulations applying to buildings, energy supply, transportation, and non-energy emissions.

Minnesota: In 2008, the Next Generation Energy Act was signed to reduce Minnesota emissions by 15% by 2015, 30% by 2025, and 80% by 2050.[34] While the law called for the development of an action plan that would make recommendations on a cap-and-trade system to meet these goals, the near-term goals will be met by a combination of an aggressive renewable portfolio standard and energy efficiency.

Connecticut: Also in 2008, the state of Connecticut passed its own Global Warming Solutions Act, establishing state level targets 10% below 1990 levels by 2020 and 80% below 2001 levels by 2050. In December 2010, the state released a report on mitigation options focused on regulatory mechanisms in addition to strengthening RGGI and reductions of non-CO_2 greenhouse gases.[35]

Renewable Portfolio Standards & Other Initiatives

A renewable portfolio standard (RPS) or renewable goal specifies that a minimum proportion of a utility's resource mix must be derived from renewable resources. These policies require electric utilities and other retail electric providers to supply a specified minimum amount—usually a percentage of total load served—with electricity from eligible resources. The standards range from modest to ambitious, and qualifying energy sources vary by state.

In general the goal of an RPS policy is to increase the development of renewable resources by creating a market demand. Increasing demand makes these technologies more economically competitive with other less expensive, but polluting, forms of electric generation. Many other policy objectives drive the adoption of an RPS or renewable goal, including climate change mitigation, job creation, energy security, and cleaner air.

The impact of an RPS on CO_2 emissions is dependent on factors such as:

- the types of resources that are eligible to meet the standard,
- the target level set by the RPS,
- the base quantity of electricity sales upon which the standard is set,
- how renewable energy credits (RECs) or attributes are tracked or counted,
- how RECs are assigned to different resources,
- banking, trading and borrowing of RECs,
- alternative compliance options, and
- coordination with other state and federal policies.

Currently, 29 US states have renewable portfolio standards. Eight others have renewable portfolio goals.

[34] Minnesota Statutes 2008 § 216B.241
[35] See http://www.ctclimatechange.com for further details on CT plans for emissions mitigation.

In addition, many states are pursuing other policy actions relating to reductions of GHGs. These policies include, but are not limited to: greenhouse gas inventories; greenhouse gas registries; climate action plans, greenhouse gas emissions targets, and emissions performance standards.

In the absence of a clear and comprehensive federal policy, many states have developed a broad array of emissions and energy related policies. For example, Massachusetts has a RPS of 15% in 2020 (rising to 25% in 2030), belongs to RGGI, requiring specific emissions reductions from power plants in the state, and has set in place aggressive energy efficiency targets through the 2008 Green Communities Act.

Hawaii, while not part of a regional climate initiative, has an even more aggressive RPS, seeking to achieve 40% renewable energy by 2030, coupled with an Energy Efficiency Portfolio Standard with the goal of reducing electricity use by 4,300 GWh by 2030. After 2013, 2% of electricity revenues in Hawaii will go towards a Public Benefit Fund, an independent entity tasked with promoting and incentivizing energy efficiency measures across the state.

EXHIBIT JIF-3

CITED DATA REQUEST RESPONSES AND ATTACHMENTS

Data Request 1-14. Please provide any technical documents generated between 2004 and 2012 (inclusive) by IPL regarding mechanisms by which the Company could or should comply with existing or expected environmental regulations, including air quality compliance planning, water quality compliance planning, and solid waste compliance planning.

This Data Request will be addressed in supplemental response

SUPPLEMENT:

Objection: IPL objects to CAC/SC Data Request 1-14 on the grounds and to the extent it solicits information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. This proceeding concerns IPL's Big Five Units and compliance with MATS. IPL further objects to the Request on the grounds and to the extent it is overly broad and unduly burdensome, particularly in its solicitation of information dating back to 2004 and information about past or possible compliance options and plans that the IURC has already approved. IPL objects to the Request on the grounds and to the extent it seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret. IPL further objects to the Request to the extent it solicits information that was prepared in anticipation of litigation or is otherwise subject to the attorney-client, work product or other applicable privileges. IPL further objection to the Request on the grounds and to the extent it solicits documents or information already in the public domain which are accessible to CAC/SC, including documents available via the IURC website.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

See CAC/SC DR 1-14, Attachment 1 (316b Report – Legal Memo Redacted).

See CAC/SC DR 1-14, Attachment 2 (AECOM proposed CCR).

See CAC/SC DR 1-14, Attachment 3, (Presentation General Wastewater Treatment Technologies).

See CAC/SC DR 1-14, Attachment 4 (Multi-Pollutant Emission Compliance Strategy – July 29, 2004).

See CAC/SC DR 1-14, Attachment 5 (Opacity Analysis Draft).

See CAC/SC DR 1-14, Attachment 6 (Methods for Reducing CO2 emissions).

316(b) APEX
PS-SC-2011-5

January 2012

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Table of Contents

List of Tables

Appendices

Key Acronyms and Chemical Names

AFUDC	Allowance for Funds Used During Construction
AIF	Actual Intake Flow
BPJ	Best Professional Judgment
BTA	Best Technology Available
B&T	Barnes & Thornburg
CCCT	Closed-Cycle Cooling Tower
CW	Cooling Water
CWA	Clean Water Act
CWIS	Cooling Water Intake Structure
DIF	Design Intake Flow
EM	Entrainment Mortality
EPA	U.S. Environmental Protection Agency
EV	Eagle Valley Generating Station
FPS	Feet Per Second
FGD	Flue Gas Desulfurization
FH&RS	Fish Handling & Return System
HS	Harding Street Station
IDEM	Indiana Department of Environmental Management
IM	Impingement Mortality
I&E M	Impingement and Entrainment Mortality
MGD	Million Gallons per Day
MTS	Modified Traveling Screen(s)
NPDES	National Pollutant Discharge Elimination System
O&M	Operating and Maintenance
PAR	Permit Application Requirements related to 122.21(r)
Pete	Petersburg Generating Station
TDD	Technical Development Document
U.S.	United States
WOUS	Waters of the United States

Executive Summary

On April 20, 2011, EPA published a draft version of the 316(b) rule that will regulate existing power generation facilities. The draft rule, in its current form, could have major impacts on the configurations of cooling water intakes for IPL's facilities. A final rule is expected to be signed by July 27, 2012, which may likely include specific timelines for compliance with the rule. Given the potential significant cost implications for compliance with the draft rule, a preliminary compliance strategy was developed in order for IPL to understand the potential impacts of the proposed rule and to ensure compliance with the proposed regulation in the specified timeframe.

The primary objective of the APEX was to determine a preliminary 316(b) compliance strategy, including plans for impingement and entrainment control reduction technologies, monitoring, permit application requirements, costs, and timing. The base case plan for this evaluation consists of the following:

Eagle Valley Units 1-6 to be retired by the end of 2015;

Harding Street Units 3-6 to be retired by the end of 2015; and

Petersburg Units 1-4 and HS Unit 7 will remain in current operational status.

The APEX team evaluated available Cooling Water Intake Structures ("CWIS") data, Cooling Water ("CW") data, impingement and entrainment mortality ("I&E M") studies, estimated impingement survival rates, identified information gaps, filled those gaps based on information available (no additional monitoring was performed based on length of monitoring needs and project deadline), and evaluated possible control strategies. The APEX team did not consider new unit or repowering options as these options are considered to be beyond the scope of a preliminary compliance control strategy. As this evaluation is based on proposed federal rule requirements, there is no cost benefit to IPL. However, there is a non-monetized benefit to IPL in regards to the reduction of the number of fish impingement and entrained (Appendix B – AQIM).

The team's analysis benefited from the expertise of an outside 316(b) consulting and engineering firm (AECOM) and determined the preliminary compliance strategy, including controls, costs, monitoring, and timing.

It is important to recognize that this report is based on the measures necessary to comply with the proposed rule as written. This rule has a number of problems and based, on previous 316(b) rulemakings and discussions with EPA, the APEX team believes the final rule is likely to be substantially different than the proposed rule. The problems with the proposed rule make it a challenge to clearly define alternatives that can be confidently determined to achieve compliance in some situations. In addition, the proposed rule provides the Indiana Department of Environmental Management's ("IDEM") Commissioner significant discretion in determining what measures are appropriate for a given facility. As a result, it is difficult to determine with confidence what measure will be required. A list of risks and uncertainties associated with the proposed rule is included in this report as Appendix A.

Despite these challenges, the APEX team has provided the most likely requirements based on available information. These recommendations are made for planning purposes and should not be considered implementable at this time. IPL should develop an implementable compliance plan after finalization of the rule and/or upon IDEM approval.

The recommended preliminary compliance strategy (non-implementable) is as follows:

Table 1: Recommended Compliance Strategy Summary

	Units	Cooling Water Intake Structures	Impingement Mortality BTA	Entrainment Mortality BTA	Monitoring	Permit Application Requirements	Capital Costs[1] ($M)	O&M Costs[1] ($M)	10-yr[1] ($M)
Eagle Valley	1-6	1	Unit 1-6 Retirement/No longer utilize CWIS for CW purposes	Unit 1-6 Retirement/No longer utilize CWIS for CW purposes	NA	IDEM Agreed Order[2]	NA	NA	NA
Harding Street[3]	3, 4	1	Shut down	Shut down	NA	NA	NA	NA	NA
	5,6	2	MTS, FH&RS; reduce velocity to <0.5 fps by installing lower capacity pumps and expanding CWIS bays	Meet EM by being fully closed cycle for Unit 7	Weekly Visual Inspections of MTS and FH&RS; One year of IM monitoring, 4 years of reduced scope monitoring	122.21(r) (2)-(8)	$3.02	$0.40	$3.93
	7	NA[4]	NA	NA	NA	NA	NA	NA	NA
Petersburg	1 2	1	MTS, FH&RS; meet numeric IM standards; remove sensitive forage species from "species of concern"	Existing conditions are BTA for EM, based on cost: monetized benefit imbalance and other environmental and practicality factors	Weekly Visual Inspections of MTS and FH&RS; 5 years of biweekly IM and EM monitoring	122.21(r) (2)-(12)	$3.93	$0.74	$7.79
	3, 4	NA[5]	NA	NA	NA	NA	NA		NA
						Total	**$6.95**	**$1.14**	**$11.7**

[1] Capital costs shown in the tables above include equipment, engineering, materials, labor and permitting. O&M includes equipment O&M and annual monitoring costs. Ten-year costs in the table include Capital + O&M. Capital costs do not include owner's costs, construction management, sales taxes, property taxes, allowance for funds used during construction ("AFUDC"), or escalation to a future date. Operating and Maintenance ("O&M") costs are based on first year cost and do not include escalation to a future date. O&M fixed costs include operating labor, maintenance labor and maintenance materials and IM and EM monitoring. Variable costs include costs for water treatment additives and energy penalties. Capital costs were developed using information obtained from vendors, information available in the EPA Technical Development Document for the Rule (Technical Development Document "TDD") (U.S.EPA 2004), general engineering references, and costs obtained from other plant operators and records. The costs developed are approximate; however, they do account for a number of site-specific factors (e.g., distance from the river to the plant, configuration and capacity of CWIS, etc.). The costs developed include 40% contingency. While these cost estimates are based on consideration of a number of site-specific factors, they are still approximate. In many cases, the costs rely on cost equations from the EPA TDD that may be out of date or not applicable. In addition, rapid changes in the price of commodities and energy have the potential to impact the estimates that are presented. Also most of these sources represent the national average costs and do not take into account regional differences in material and labor costs. Therefore, while the costs presented here are useful for considering the relative costs of various alternatives, the actual costs of implementing any of these alternatives could be substantially higher and will need to be determined as part of a detailed engineering study for each facility chosen compliance option(s).

[2] IPL will need to enter into an Agreed Order with IDEM committing to the retirement of units 1-6 no later than February 2013.

[3] HS path includes retirement of Units 3-6; Utilization of HS CWIS 2 for HS Unit 7 make-up water (2 pumps @ 16,000 gpm each).

[4] Based on the definitions of "cooling water intake structure", B&T believes the 316(b) regulated "cooling water intake structure" would extend only from the point water is removed from the White River up to the intake pumps in CWIS 2. B&T believes the pipes past that point up to and including the junction box and the intake pumps for Unit 7 would be part of the in-plant water distribution system. However, even if the government were to conclude that the "cooling water intake structure" extended up to and including the Unit 7 intake pumps, the proposed technical requirements that

would apply to the cooling water intake structure likely would be implemented at CWIS 2 circulating water pump house and not further downstream at the Unit 7 intake pumps.

5 At this time, the Petersburg discharge canal has been treated under its NPDES permit as a point source and the water contained in the discharge canal has been treated as a process wastewater subject to the requirements in the NPDES permit at the point that wastewater is discharged from the discharge canal into the receiving water body. Therefore, the discharge canal is not currently considered waters of the United States and removing water from the discharge canal would not be considered withdrawing cooling water from a water of the United States as required in the definition of "cooling water intake structure" in the proposed rule.

The preliminary compliance strategy includes installation of modified traveling screens ("MTS"), fish handling and return systems ("FH&RS"), and modified existing CWIS/reduced pump size. The proposed compliance strategy is not based on detailed engineering studies. Schedules above reflect timing needs associated with installation of these controls based on the proposed rule compliance dates (if provided in proposed rule). The schedules recommended are preliminary in nature. Development of detailed schedules is only possible once detailed engineering studies for Pete and HS have been conducted for each unit/CWIS after the promulgation of the final rule. It is strongly recommended that the preliminary schedules outlined herein be finalized after EPA's signing of the final 316(b) Rule (estimated date of July 27, 2012), IPL's review of the final rule, and/or detailed engineering studies, and/or IDEM's approval of BTA are completed.

Background

On March 28, 2011, EPA signed the proposal for Section 316(b) rules of the Clean Water Act ("CWA") for cooling water intake structures related to existing facilities and new units at existing facilities. EPA is obligated to finalize the rule by July 27, 2012.

The withdrawal of cooling water may adversely impact aquatic organisms, including fish, shellfish, and marine mammals. Impacts are defined as impingement (where aquatic organisms are pinned against screens or other parts of a CWIS) and entrainment (when organisms are killed or injured as they are drawn through cooling water systems). Regulations for existing facilities under Section 316(b) were previously promulgated in both 2004 and 2006. Litigation followed both of these actions, and EPA plans to combine and re-promulgate final rules for all existing CWIS facilities in 2012. As part of the litigation process from the previous 316(b) rules, the U.S. Supreme Court, in 2009, held that the Agency may consider cost-benefit analysis in choosing among regulatory options, but did not hold that the Agency must consider it.

Principal Requirements

The proposed rule leaves much to the discretion of the IDEM permit writer (and the EPA Region that reviews the permit), including but not limited to EM BTA, monitoring, and compliance schedule. The proposed rule sets separate standards for I&E M:

1. **IM BTA.** For existing plants (and new units added to existing plants) above 2 MGD (design intake flow), impingement mortality must be no more than 12% (annual average) and 31% (monthly average) or intake velocity must be ≤ ½ ft/sec. EPA thinks this standard can be accomplished by modified traveling screens with a fish handling and return system. EPA expects that a wet cooling tower would meet the 0.5 ft/sec velocity requirement.
2. **EM BTA for Existing Units at Existing Facilities.** For plants above 2 MGD (design intake flow), IDEM National Pollutant Discharge Elimination System ("NPDES") permit writers must set case-by-case limits for "maximum reduction" of entrainment mortality based on a site-specific assessment of technology feasibility and performance (including, at a minimum, the performance of closed-cycle cooling

and fine mesh screens with a slot size ≤ 2 mm), "social costs," benefits, energy and environmental impacts, and other factors.[1]

3. **EM BTA for New Units at Existing Facilities.** For new units that (a) commence construction at existing facilities after the effective date of the rule, (b) have flows above 2 MGD, and (c) do not qualify as "new facilities" under the Phase I Rule, intake flow must be commensurate with recirculating closed-cycle cooling,[2] or else entrainment mortality must be at least 90% what closed-cycle cooling could do. Closed-cycle cooling includes wet or dry cooling towers, and cooling ponds that are not "waters of the U.S." and do not rely on "continuous" intake flows.

APEX Objectives

The primary objective of the APEX is to develop a preliminary 316(b) compliance strategy, including preliminary plans for impingement and entrainment mortality control reduction technologies, monitoring, permit application requirements, costs, and timing.

The goal of this project is to recommend a preliminary compliance strategy that has a low risk of non-compliance and high success level of approval by IDEM at a low overall cost to IPL, if possible. This preliminary compliance strategy is also to include a recommended strategy for compliance monitoring (if applicable), and address permit application requirements. Lastly, this compliance strategy is to include a preliminary recommendation for general timing associated with control installations, PAR, and other necessary actions.

This APEX team believes that it will be in IPL's interest to carefully plan for the implementation of Section 316(b) including both anticipating changes in the rule from the proposal and advocating for the most cost-effective approaches to compliance. Such an approach should include careful evaluation of available compliance approaches including planning for the potential that closed cycle cooling may be required. The APEX team makes a distinction between a preliminary compliance strategy intended to attempt to minimize IPL's cost of compliance and a "planning outcome" intended to support financial planning by IPL. Given the uncertainty in the proposed rule, the APEX team believes that this distinction is an important one. While the recommended strategy may strive to minimize costs, IDEM and EPA have authority to affect the outcome so it is likely to be prudent to anticipate a higher cost scenario in the financial planning process.

APEX Scope

The scope of this APEX includes identification of information gaps, filling those gaps, evaluation of possible control reduction strategies, and determination of preliminary compliance strategy. The first step is to review all existing 316(b) information and identify and fill any 316(b) data gaps associated with 316(b) studies, CW and CWIS data, performance studies, and evaluations required to support BTA determination (developed

[1] The complete list of factors is: (1) numbers and types of organisms entrained, (2) entrainment impacts on the waterbody, (3) quantified and qualitative social benefits and social costs of available entrainment technologies, including ecological benefits and benefits to any threatened or endangered species, (4) thermal discharge impacts, (5) impacts on the reliability of energy delivery within the immediate area, (6) impact of changes in particulate emissions or other pollutants associated with entrainment technologies, (7) land availability inasmuch as it relates to the feasibility of entrainment technology, (8) remaining useful plant life, and (9) impacts on water consumption.

[2] EPA proposes to define optimized cooling towers as those capable of achieving flow reductions of 97.5% for freshwater sources (operating at a minimum of 3.0 cycles of concentration) and 94.9% for saltwater sources (operating at a minimum of 1.5 cycles of concentration. § 125.92[definition for closed-cycle recirculating system]).

under suspended rule). The second step is to determine rule applicability and potential implications relative to and with emphasis on major rule requirements. The third step is to evaluate existing technologies and/or operating measures that may currently provide some level of IM and EM control and estimate percent reduction. The fourth step is to complete a screening evaluation of technologies to identify potentially feasible cost-effective technological and/or operational measures which would potentially allow for compliance with the draft rule requirements. The fifth step is to develop a technical memorandum which includes but is not limited to the APEX goal items #1-6 and 9 listed within the APEX Charter (provided by AECOM in Appendix D of this report). This step includes development and evaluation of multiple compliance strategies by the external consultant. This memo serves as the basis for the preliminary compliance strategy. The final step is to determine the preferred preliminary compliance strategy, including controls to be installed with associated cost and timing, compliance monitoring, and permit application.

APEX Design

The 316(b) APEX team included representation from different functional areas from across the Company, including IPL and AES Environmental Affairs, plant (Petersburg, Harding Street, and Eagle Valley) leadership, plant engineering, and plant environmental, Project Development, Markets & Risks. A 316(b) consulting firm, AECOM, also provided technical expertise throughout the APEX by participating in APEX meetings, providing ongoing support, and developing a report to include compliance options with associated costs, compliance/regulatory approval risk levels, and a preliminary compliance strategy recommendation.

APEX Specific Findings and Recommendations

Baseline 316(b) and Compliance Assessment

The first step in the APEX process is to review all existing 316(b) information and data and identify and fill any 316(b) data gaps associated with 316(b) studies, CW and CWIS data, performance studies, and evaluations required to support BTA determination (developed under suspended rule). The second step is to determine rule applicability and potential implications relative to and with emphasis on major rule requirements. The following tables show information available at commencement and/or during the APEX process:

Table 2: IPL CWIS Current Information

Current Conditions			
	Eagle Valley	**Harding Street**	**Petersburg**
Design intake Flow Rate	335.4 MGD	238.8 MGD	427.7 MGD
Average intake Flow Rate[1]	156.2 MGD	108.2 MGD	383.44 MGD
Forebays	6 forebays	2 separate CWIS: "CHU 1-4": 8 forebays - Units 1 thru 4; Units 1&2 bays not used "CWPH": 2 forebays for Units 5 and 6 Unit 7 make up water from junction box	Unit 1: 2 forebays Unit 2: 4 forebays Units 3 and 4 makeup water from 1&2 discharge Unit 2: ½ CCCT (summer months and low water levels)
Travelling Screens	12 - 96" wide, 3/8 openings	12 - 96" wide, 3/8 openings	6- 120" wide, 3/8 openings
Circ Pumps	Units 1-3: 6 @ 15,500 gpm Unit 6: 2 @ 25,000 gpm Units 4 and 5: 4 @ 21,500 gpm	CHU1-4: 4 @ 16,100 gpm CWPH: 4 @ 24,750 gpm	Unit 1: 2 @ 56,000 gpm Unit 2: 4 @ 46,250 gpm
Calculated Design Through-Screen Intake Velocity	Units 1,2,3: 0.77 fps Units 4&5: 1.07 fps Unit 6: 1.24 fps	CHU 1-4: 0.97 fps CWPH: 1.17 fps	Unit 1: 1.60 fps Unit 2: 1.32 fps
Calculated Average Through-Screen intake Velocity[1]	Units 1,2,3: 0.36 fps Units 4&5: 0.50 fps Unit 6: 0.58 fps	CHU 1-4: 0.44 fps CWPH: 0.53 fps	Unit 1: 1.43 fps Unit 2: 1.18 fps
Installed technology	Traveling screens, no fish return	Traveling screens, no fish return	Traveling screens, no fish return

[1] Average flow rates are from water usage records from a three year period from 2008 through 2011. Average velocities were calculated using average flow rates.

Table 3: IPL Projected 2016 CWIS Information

2016 Conditions			
	Eagle Valley	**Harding Street**	**Petersburg**
Design intake Flow Rate	N/A	46.1 MGD	427.7 MGD
Average intake Flow Rate[1]	N/A	23.0 MGD (assumes one pump operating)	383.44 MGD
Through Screen Velocity DIF	N/A	CWIS 5/6: 1.17 fps	Unit 1: 1.60 fps Unit 2: 1.32 fps

[1] Average intake flow rate for Petersburg is estimated based on assumption that the proportion of AIF to DIF is the same as in the historical record. Average intake flow rate for Harding Street is based on understanding that only one of two pumps will be required during typical operation conditions.

Table 4: 316(b) Compliance Assessment

316(b) Requirements	Compliance Options	EV[1]	HS[1]	PETE[1]
IM BTA (125.94(b))	<0.5 fps	N/A	[redacted]	[redacted]
	Less than 15% debris blocking CWIS		TBD[6]	NA
	12% annual (IM) 31% monthly (IM)		N/A	[redacted]
IM BTA (125.94(b))	MTS and FH&RS	N/A	[redacted]	[redacted]
EM BTA (125.94(c))	Case By Case Determination[2]	N/A	[redacted]	No additional control
PAR (122.21(r) and 125.95)	(2)-(12)[3]	N/A[4]	[redacted]	[redacted]

1 Compliance determined on 2016 conditions.
2 EPA requires at a minimum CCCT and fines mesh screens < 2 MM to be evaluated as potential EM technology.
3 HS subject to 122.21(r) (2)-(8) only.
4 Assumes IDEM agrees to not require EV to submit PAR via Agreed Order.
5 The information previously submitted as denoted will require revisions to ensure compliance with the proposed PAR.
6 EPA assumes compliance with the <0.5 fps will ensure compliance with this proposed requirement.

The first column of the table above shows the proposed rule compliance requirements. The second column shows the proposed rule compliance options for each of the major rule requirements, while the remaining columns show 2016 facility status. “N/A” represents a compliance option which was not applicable based on 2016 conditions.

Values highlighted in green are those that currently show compliance with the proposed major regulatory requirements. Values highlighted in red are those do not meet the proposed major regulatory requirements.

Recommended Compliance Strategies

The APEX team evaluated compliance options for post-2015 CWIS at the coal-fired IPL facilities (**Appendix C: APEX Compliance Strategy Plant Options)**. Each IPL station has recently received, or is soon to receive its proposed new NPDES permit with 5-year renewal cycle. This means that the final rule will be issued during the time that the plants’ NPDES permits are active and that the earliest requirements of the 316(b) rule, as written in the draft rule, would be due in the middle of each plant’s permit cycle. It is unclear how the state permitting authority will enforce these requirements for facilities with active NPDES permits, such as the IPL stations. The agency could modify existing permits, require separate submittals outside the permitting timeframe or put off the submittal requirements until the next permit cycle. It is also unclear how the agency will handle the permit application requirements in lieu of the soon to be announced retirement of several IPL generating units. For the purposes of this report, it is assumed that existing permits will be modified to include new 316(b) requirements and all facilities will be required to submit the earliest documents within 6 months of the effective date of the final 316(b) rule.

IPL has proposed retiring the EV coal-fired facility and retiring HS Units 3, 4, 5, and 6 by the end of 2015. These actions will leave Petersburg Units 1, 2, 3, and 4 and HS Unit 7 in operation after approximately 2015. The compliance paths described below assume that IPL will notify IDEM of the closure of EV and will request that IDEM not require compliance with the final 316(b) rule for that station.

Several compliance options were identified and are summarized in Tables 5-7.

Table 5: Petersburg Compliance Options

Option	Units	CWIS	IM BTA	EM BTA	PAR	Risk	Capital ($M)	O&M ($M)	10-Yr ($M)
1	1 2	1	MTS, FH&RS[1]	Existing Operations	122.21(r)(2)-(12)	2.75	3.93	0.74	7.79
	3 4	NA	NA	NA	NA	NA	NA	NA	NA
2	1	1	MTS, FH&RS, reduce pump size	Reduce flow (reduce pump size)	122.21(r)(2)-(12)	2	7.33	0.74	72.99
	2		CCCT	CCCT			51.3	2.7	
	3 4	NA	NA	NA	NA	NA	NA	NA	NA
3	1 2	1	MTS, FH&RS, CCCT	CCCT	122.21(r)(2)-(12)	1	151.93	6.39	178.24
	3 4		CCCT	CCCT		NA	NA	NA	NA

[1] Assumes both gizzard and threadfin shad are not considered species of concern by IDEM and EPA.

Table 6: Harding Street Compliance Options

Option	Units	CWIS	IM BTA	EM BTA	PAR	Risk	Capital ($M)	O&M ($M)	10-Yr ($M)
1	3								
	4	1	NA	NA					
	5								
	6		NA	NA	NA	NA	NA	NA	NA
	7	2	CCCT, MTS, FH&RS, modify intake structure, reduce pump size	CCCT	122.21(r)(2)-(8)	1.5	3.02	0.4	3.93
2	3								
	4	1	NA	NA					
	5								
	6		NA	NA	NA	NA	NA	NA	NA
	7	2	CCCT, MTS, FH&RS, modify intake structure, reduce pump size	CCCT	122.21(r)(2), (3), (4) and (6)*	2	3.00	0.15	3.66

* If approved by IDEM.

Table 7: Eagle Valley Compliance Options

Option	Units	CWIS	IM BTA	EM BTA	PAR	Risk	Capital ($M)	O&M ($M)	10-Yr ($M)
1	1								
	2								
	3								
	4								
	5								
	6	1	NA	NA	122.21 (r)(2)-(8)	1.5	0	0.02	0.02
2	1								
	2								
	3								
	4								
	5								
	6	1	NA	NA	IDEM Agreed Order	2	0	0	0

* Costs are defined under Table 1.

A "high" risk option represents one or more of the following:

1. high risk of non-compliance with the proposed 316(b) rule,
2. technical issues with control reduction technologies which may lead to technical infeasibility, and/or
3. low probability of approval from IDEM/EPA.

A "medium" risk option represents one or more of the following:

1. medium risk of non-compliance with the 316(b) rule,
2. technical issues with control reduction technologies which may lead to technical infeasibility, and/or
3. medium probability of approval from IDEM/EPA.

A "moderate" risk option represents one or more of the following:

1. low-medium risk of non-compliance with the 316(b) rule,
2. some risk of permitting issues associated with 40 CFR 122.21(r), and/or
3. medium-high probability of approval from IDEM/EPA.

A "low" risk option represents one that has a low to no risk of non-compliance with the proposed 316(b) rule and/or a high probability of approval from IDEM/EPA.

The APEX team did not consider options which provided a high or medium risk because compliance with the standard is obligatory and non-compliance would result in forced outages and significant environmental fines and penalties. Only low and moderate risk options were considered. In addition, the APEX team did not develop and assess options for potential new facilities or re-powered facilities as this is considered outside the scope of this APEX. In this particular APEX review, there were no high to medium risk options. All other technologies initially considered were not included in this report as these technologies were considered technically infeasible. Please see attached AECOM report (Appendix D) for a comprehensive list of control reduction technologies.

The proposed rule requires the installation and operation of MTS and FH&RS for all CWIS with traveling screens as part of IM BTA. Therefore, both HS and Pete are required to meet this provision of the proposed rule. As plant modifications will need to occur, detailed engineering studies are necessary for both HS and Pete.

Petersburg

All three options were considered for Pete as these options are considered low-moderate risk options. Option 1 includes modifying the existing traveling screens and adding a FH&RS. Option 2 includes Unit 2 conversion to CCC, MTS/FH&RS, and reduction in pump size (in order to reduce intake flow velocity to less than 0.5 fps). Option 3 includes conversion of Units 1 and 2 to CCC and MTS/FH&RS. The capital and O&M costs associated with Option 3 are three times Pete Option 2. However, Option 3 presents low to no risk. The capital and O&M costs associated with Option 2 are more than 10 times Option 1. However, Option 2 presents less risk than Option 1.

Option 1 is the recommended preliminary compliance strategy for Petersburg because it is the least disruptive compliance path of the three options, does not cause an increase in air emissions, does not impose space concerns, does not impose local energy reliability concerns and is the more economical option. This option does pose low-medium risk due to the uncertainty associated with the following:

- Recommended control reduction technology resulting in the facility meeting the proposed numeric performance limitations; and

- Approved species of concern list.

Due to these uncertainties, the APEX team recommends the following for Petersburg:

- Advocate to IDEM for the removal of gizzard and threadfin shad and other forage species from consideration in IM survivability rates. Other hardier species survivability approaches 85%. By eliminating the above species, which comprise 73% of the fish species impinged at the facility, the APEX team believes that the facility may be able to comply with the proposed numeric performance limitations by adding MTS and FH&RS.
- Propose existing conditions as BTA for EM. IDEM will establish BTA on a site-specific basis and the facility could be made to install additional EM reduction technologies which are not reflected in Option 1. To minimize the potential that IDEM concludes that closed-cycle cooling is BTA for EM, the APEX team recommends that the entrainment mortality submittals emphasize the very high costs relative to the benefits and other adverse environmental impacts associated with closed cycle cooling. The cost to benefit ratio of closed cycle cooling exceeds 800:1. This very high cost to benefit ratio should be emphasized in the submittals to IDEM. In addition, the other adverse environmental impacts associated with closed cycle cooling should be clearly documented and emphasized. Operation of closed cycle cooling towers will increase energy consumption by the plant; increase air emissions (particulates due to cooling tower drift and overall emissions due to decreased plant efficiency); increase water consumption; increase noise levels; increase safety concerns; and increase the potential impacts to plant and therefore grid reliability.
- Measure IM and EM relatively early (see Table 10 below); and
- Perform IM retrofit relatively early (see Table 10 below).

As part of the approach associated with this option, IPL will need to perform IM monitoring post-installation of the MTS and FH&RS (2014) in order to verify compliance with the proposed numeric performance limitations. This monitoring will be conducted post-control installation (2015) and results submitted to IDEM no later than mid-2016. If IM monitoring results indicate that the facility will not be able to meet the proposed numeric limitations by utilizing the installed control reduction equipment, IPL will need to reassess IM BTA compliance options. If the IM limitations are not achieved at the Petersburg facility, additional modifications may be required. These could include expanding the CWIS to achieve <0.5 fps intake velocity. The implications of this expansion would be dependent on the cooling configuration that was determined to be BTA for EM. If once-through cooling is maintained, achieving intake velocity < 0.5 fps would likely be very expensive and potentially infeasible. In this case, there would be relatively limited options under the proposed rule. Conceivably this could lead to the requirement to install closed-cycle cooling to reduce the intake velocity. However, discussions with EPA have indicated that it was not their intention to require closed-cycle cooling to reduce IM. As a result, the APEX team believes the final rule may include provisions to limit the potential of this outcome including dispensing with the impingement mortality performance standard. If IPL should need to implement Option 2 based on the IM monitoring results, IPL will need to ensure the modifications are completed no later than September 2020 (see Table 11 for timing and AECOM Table 6.3 for costs – Appendix D).

HS will continue to operate Unit 7 and will continue to operate one of the existing CWISs to provide water to Unit 7 and other plant needs. HS will be required to retrofit the existing traveling water screens to Ristroph-type screens with a fish return system. In addition, IPL will modify the Unit 5&6 intake structure so that the intake velocity is less than 0.5 fps. Both options 1 and 2 were considered for HS which require the above control reduction technologies.

Under Option 2, HS would commit to retirement of Units 3-6 early in the PAR process (March 2013). This would leave Unit 7, which operates with closed cycle cooling, as the only active unit at the facility. Unit 7 draws makeup water from the "junction box" which is fed from the CWIS from Units 5&6 and Units 3&4. HS proposes to keep the CWIS for Units 5&6 in operation to maintain flow to the junction box to provide makeup water for Unit 7 cooling tower and ash sluice water. Under this option, existing circulating water pumps would be larger than necessary and could be replaced with pumps of lesser capacity and the intake modified to reduce the intake velocity to less than 0.5 fps. Sufficient flow for the facility can be provided by one pump at 16,000 gpm. Pumps will be installed in two bays of the existing CWIS with one pump operating and the other in standby. Therefore, modified traveling screens need only be installed in two bays of the existing CWIS. The existing CWIS would be modified to increase screen area to ensure the design intake velocity is less than 0.5 fps. HS would be required to demonstrate that the maximum design intake velocity is less than 0.5 fps and keep debris from fouling the screens (less than 15% blockage of the screen). HS would also have to submit the reports identified in 122.21(r)(2), (3), (4), and (6) assuming IDEM approval of this option.

Option 1 includes the same IM control reduction technology and CWIS modification discussed under Option 2. However, Option 1 does not require HS to commit to unit retirement by March 2013 and allows more time for the facility to assess possible re-power options. Under this option, HS would be required to commit to unit retirement by March 2016. The difference between the two options is the timing of notification of IDEM of the planned closure of the once-through units at HS.

Both options consider the continued utilization of the existing Unit 7 CCC system. Capital and O&M costs for Options 1 and 2 are comparable.

Current average intake flow for the plant is less than 125 MGD; therefore HS will not be required to submit the entrainment mortality reports under either operational option described above. However, IDEM must make a site-specific BTA determination regarding BTA for entrainment mortality. Since the future plan is for Unit 7 to operate as closed cycle and all other units would be retired, HS will be considered compliant with BTA for entrainment under the proposed rule.

Option 1 is the recommended preliminary compliance strategy for Harding Street because it is a low-moderate risk option which allows for flexibility regarding HS's commitment to unit retirement. HS will be required to demonstrate that the maximum design intake velocity is less than 0.5 fps and keep debris from fouling the screens (less than 15% blockage of the screen) and modify existing traveling screens. HS will be required to submit the applicable PAR information by the deadlines identified in the modified NPDES permit for both CWIS (see Table 9). This option will not require HS to commit to unit shutdown by March 2013 and will allow more time for the facility to assess possible re-power options at the facility. Under this option HS will have to commit to a unit retirement date by March 2016.

The actual IM BTA compliance date will be determined by IDEM upon receipt of the facility's IM Reduction Plan.

Eagle Valley

The APEX team studied compliance options available to EV considering the plans to close the plant by the end of 2015. Both options 1 and 2 were considered based on a memorandum prepared by Barnes & Thornburg included in the AECOM Technical Memo (Appendix D).

Option 1 will require EV to gather various information and perform extensive and expensive studies identified in the proposed § 122.21(r). This option for EV appears to be an inefficient use of both time and money given the fact that EV will cease operations in the relatively near future. Therefore, though this option has no risk from either a compliance or negotiation with IDEM perspective, it does not appear to be a very practical option for EV particularly if information identified in the proposed § 122.21(r) that is required to be submitted at later time periods would need to be gathered and submitted because those deadlines also precede the retirement date for the EV units.

Option 2 is the recommended control strategy for Eagle Valley because it is the low-moderate risk option with no cost implications and was the recommended option by external legal counsel (B&T). As previously discussed, this option includes the retirement of Units 1-6 by the end of 2015. IPL will need to inform the IDEM NPDES permit writer that all of the units at EV will be retired and request that IDEM modify the EV NPDES permit to incorporate the requirements in the final 316(b) rule for that reason. Assuming IDEM agrees with this approach for EV, IDEM would modify EV's NPDES permit to incorporate the 316(b) requirements and would enter into an Agreed Order with IPL in which those requirements would be stayed and IPL would commit to retiring the EV units by 2015. The Agreed Order needs to contain an additional provision that would provide that IPL would not need to submit the proposed § 122.21(r) information due to unit retirement. The Agreed Order also could contain a provision imposing a monetary penalty for failing to retire the units by the end of 2015. These additional provisions should help alleviate concerns IDEM or EPA may have that IPL is not serious about retiring the units and is only trying to postpone its compliance with the 316(b) requirements at EV. However, this option does pose some risk from a negotiation with IDEM perspective. According to the proposed 316(b) rule, the application requirements in the proposed § 125.95(b)(1) apply to "the owner or operator of a facility subject to" 40 CFR Part 125, Subpart J. Therefore, because EV still will be a facility subject to the 316(b) rule at the time the rule is finalized and would no longer be subject to the rule after the units have been retired, IDEM may decide based on the 316(b) regulation and/or input from EPA Region 5, that it must require EV to submit limited information related to proposed § 122.21(r).

Compliance Monitoring Strategy

The proposed 316(b) regulation contains significant requirements for entrainment and impingement monitoring. These requirements are vaguely defined by the regulation and in some cases there is contradictory language on their content and applicability. Under the proposed rule IDEM has substantial discretion over the frequency, duration, and nature of both IM and EM monitoring. As a result, there is a wide range of requirements that may be applied to IPL's facilities. In this section the APEX team presents potential monitoring requirements based on review of the rule and agency precedent; actual monitoring requirements may be substantially different as determined by IDEM.

Impingement Mortality Monitoring Requirements:

The proposed rule requires monitoring of impingement rates at all facilities and monitoring to demonstrate the effectiveness of the technology at reducing IM when the intake velocity if >0.5 fps. The frequency and duration of the monitoring of IM is not clearly defined in the rule. For facilities with intake velocities of <0.5 fps, the rule requires either a demonstration that the maximum design velocity is less than this value or monitoring of the actual intake velocity on a twice per week basis.

The rule is unclear as to when the monitoring must start or how long it must continue. Submittal of the IM study results is required 3.5 years after finalization of the rule. This suggests that the impingement mortality monitoring required by the impingement mortality reduction plan must be completed by that time. However, the installation of technology for reducing IM is not required to be complete until eight years after finalization. It is not clear how this discrepancy will be resolved in the final rule or interpreted by IDEM. This discrepancy has been considered, and a strategy to resolve it developed, in the planning of strategy and estimation of costs for the IPL facilities.

In order to evaluate the approximate costs associated with the IM monitoring, the APEX team has assumed that monitoring at HS will occur once within the time frame necessary to provide results to IDEM by the due date 3.5 years after finalization of the rule, March 2016. This monitoring will occur biweekly with 12 monitoring events consisting of latent mortality monitoring; the remaining 14 monitoring events consisting of enumeration only. Monitoring would be designed to collect specimens at the effluent from the screens, identify naturally moribund individuals and species of concern and will account for episodic events. The APEX team estimated that this monitoring would cost approximately $250,000 per year (1 yr. period only). The APEX team assumed that enumeration-only monitoring would be required as a condition of the facility's NPDES permit after installation of the modified traveling screen system and has estimated a cost of approximately $100,000 for this monitoring (2019 forward).

At Petersburg, the APEX team assumed that IM monitoring would begin shortly after installation of modified traveling screens (2015) and within the time frame necessary to provide the first year's results to IDEM by the due date of March 2016. The APEX team also assumed that IM monitoring would continue each of the following four years of the NPDES permit period (5 year total). This monitoring would occur biweekly consisting of 12 monitoring events of latent mortality monitoring; the remaining 14 monitoring events consisting of enumeration only each year. For costing purposes, the APEX team assumed this monitoring would occur for five years after installation of the modified traveling screens system. Monitoring costs were estimated at $250,000 per year for this monitoring

Entrainment Mortality Monitoring Requirements:

The proposed rule requires the development of an entrainment mortality data collection plan. This plan is likely to require conditions for some entrainment monitoring. However, the rule does not contain specific requirements governing the frequency, nature, or duration of entrainment monitoring. Therefore, it is difficult to accurately predict the costs associated with any entrainment monitoring that will be required. To estimate potential costs, a number of assumptions were made.

The draft Entrainment Characterization Study is required to be submitted with peer reviewer identified within six months of finalization of the rule. The peer reviewed plan is required to be submitted six months after that and the EM study to be completed within four years. The APEX team assumed that monitoring will begin at the Petersburg Generating Station after submittal and acceptance of the peer reviewed Entrainment Characterization Study and will be conducted and reported the next year within the required four-year period (2013-2014). Additional monitoring is not planned again until after the Director has rendered a BTA determination. For the purposes of estimating the potential costs, the APEX team assumed that entrainment monitoring would consist of enumeration only. Monitoring could occur on a biweekly basis concurrent with impingement sampling. If sampling is not concurrent with impingement sampling, costs would increase substantially. Monitoring costs were estimated at $150,000 per year.

Entrainment monitoring is not expected to be required at the Harding Street Station.

Preliminary Compliance Schedule

Table 8: Eagle Valley Compliance Schedule

Compliance Step	Accomplish by Date	Notes
Submit NPDES permit modification request with associated Compliance Schedule	September 2012	Commit to plant closure
Ensure Agreed Order issued by IDEM	February 2013	Prior to March 2013 PAR compliance date

Table 9: Harding Street Compliance Schedule

Compliance Step	Accomplish by Date	Notes
Submit 122.21(r) (2, 3, 4, 5, 6, 7, and 8)	March 2013	Propose to achieve compliance through operation of MTS and FH&RS
Monitor for IM	Conduct latent mortality IM monitoring in 2014	Submit results within 3.5 years of rule finalization
Complete detailed engineering study	2014	For MTS, FH&RS, and CWIS modification
Install modified traveling screens, fish return and handling system in 2 bays	Install 2018	Achieve IM compliance through operation of MTS, FH&RS, and modified CWIS (<0.5 fps)
Replace 24,500 gpm pumps with two 16,000 gpm pumps	2018	Achieve IM compliance through operation of MTS, FH&RS, and reduced design intake flow velocity
Modify CWIS	2018	Achieve IM compliance through operation of MTS, FH&RS, and reduced design intake flow velocity
Perform IM monitoring enumeration only	2019 onward	Expected permit condition

The recommended compliance path for Harding Street Station, Option 1 above, is summarized with costs (capital and O&M), schedules, and reporting and monitoring requirements in AECOM's 316(b) Compliance Strategy Plan **Table 6.2**.

Table 10: Pete Option 1 Compliance Schedule

Compliance Step	Accomplish by Date	Notes
Submit 122.21(r) (2, 3, 4, 5, 6, 7, 8)	March 2013	Propose to achieve compliance through operation of MTS and FH&RS; make case for not considering forage species
Submit 122.21(r) (9)	Draft plan in March 2013; Peer reviewed EM study plan by September 2013	
Monitor for EM	Complete in 2013-2014	To support benefits assessment
Detailed Engineering Study for MTS and FH&RS	2013	
Install MTS and FH&RS	2014	Installed to support evaluation of performance required by 122.21(r)(6). Potential that installation not necessary until 2020 when compliance with IM limitations required.
Monitor for IM	2015 – 2019; Submit results of first year of study in mid-2016	Demonstrate achievement of numeric standards
Submit 122.21(r) (10, 11, 12)	September 2017	Advocate that existing system is BTA for EM based on costs relative to benefits and other factors
Monitor for EM	2018-2022	

Table 11: Pete Option 2 Compliance Schedule*

Compliance Step	Accomplish by Date	Notes
Submit 122.21(r) (2, 3, 4, 5, 6, 7, 8)	March 2013	Propose to achieve compliance through operation of MTS and FH&RS; make case for not considering forage species
Submit 122.21(r) (9)	Draft plan in March 2013; Peer reviewed EM study plan by September 2013	
Monitor for EM	Complete in 2013-2014	To support benefits assessment
Detailed Engineering Study for MTS and FH&RS	2013	
Install MTS and FH&RS	2014	
Monitor for IM	2015 – 2019; Submit results of first year of study in 2016	Demonstrate achievement of numeric standards
Submit 122.21(r) (10, 11, 12)	September 2017	Propose that existing system is BTA for EM – IDEM does not agree
Engineering for CCC conversion	2018	
Convert Unit 2 to CCC	2019	Reduces flow and velocity
Modify CWIS/reduce pump capacity	2019	Reduces velocity to <0.5 fps for IM BTA
Monitor for EM	2020-2022	Expected NPDES permit condition

* Potential compliance path for financial planning purposes if facility does not meet IM numeric performance limits.

Preliminary Control Reduction Strategy

The preliminary control reduction strategy includes installation of MTS, FH&RS, and modification of CWIS. It is expected that the total timing needed for a MTS and FH&RS from engineering design phase to operation can range from six to nine months.

The schedules recommended are preliminary in nature and development of detailed schedules is only possible once detailed engineering studies have been conducted for each unit. It is strongly recommended that these schedules not be finalized until after EPA finalizes the proposed rule and potentially IPL receives the proposed required IDEM approval.

The recommended schedule for installation of MTS and FH&RS to be completed for Petersburg is as follows: Unit 2 in Spring 2014; Unit 3 Fall 2014. Unit 1 is currently scheduled for an outage in Fall 2014. This outage should allow for sufficient time for installation of controls given that the total timing needed for a MTS and FH&RS from engineering design phase to operation can range from six to nine months (four months for design and two months for installation provided by AECOM). Installation of MTS and FH&RS and associated monitoring relatively early will allow for the facility to determine if it can meet the proposed IM BTA numeric performance limitations. If it is determined that the facility cannot meet the IM BTA numeric performance limitation and/or IDEM determines EM BTA to be additional control reduction technologies, Pete will need to re-assess the other technically feasible options provided in Table 6.

The recommended schedule for installation of IM reduction controls at Harding Street to be completed is as follows: CWIS 5/6 in Spring 2018. This work can be done while Unit 7 is in operation and will not require an outage (same timing as Pete: six to nine months).

The recommended schedule for a final Agreed Order from IDEM for Eagle Valley should be completed no later than six months after the final effective date of the rule. It is recommended that IPL submit a request to IDEM committing to plant retirement in Fall 2012 to ensure that IDEM issues an enforceable document relieving EV of its obligation to comply with the PAR prior to March 2013.

Future Action

The APEX team focused compliance efforts on the draft 316(b) rule as currently proposed. There is a significant possibility that legal challenges, changes to the draft rule, or factors outside of this draft rule will occur prior to finalization of the rule and have a significant effect on IPL's overall preliminary compliance strategy. This could include developments in control technologies, revised IM BTA requirements, compliance monitoring provisions, and/or permit application requirements in the final rule.

In addition, IPL Corporate Environmental developed comments on the proposed rule which were submitted to EPA prior to the comment deadline of July 19, 2011. These comments included recommendations to EPA to ensure CCCT is equal to both IM and EM BTA, eliminate monitoring for CCCT, and allowing for case by case IM BTA. IPL also participated in comment preparation by industry groups. IPL's efforts along with those of others in the industry may affect the stringency of the final rule.

IPL will continue to monitor regulatory activity and update compliance strategy recommendations as the regulatory outlook changes and additional information becomes available.

APPENDIX A: Proposed Rule Risks & Uncertainties

Risks and Uncertainties

1. **Numeric Impingement Mortality and Alternative Design Velocity Limits.** The numeric performance limits on impingement mortality (or, alternatively, intake velocity) may be hard to meet, or at least expensive. The rule provides no opportunity to seek alternative standards, whether based on cost-benefit, technical infeasibility, costs greater than EPA considered, or any other factor.
2. **Fish Handling and Return System.** The proposed rule contains no exemption or site-specific alternative based on technical infeasibility of adding a fish handling and return system. This is a potential issue at HS and Pete due to flooding, freezing, and logistics (location).
3. **EM BTA.** Case-by-case "maximum reduction" of entrainment mortality warranted after considering 9 "factors". IDEM must provide written explanation of BTA, including reasons for rejecting any technologies that perform better than those selected. IDEM may reject otherwise available technology for EM if social costs of compliance are "not justified" by the social benefits or there are adverse impacts that cannot be mitigated and the Commissioner deems "unacceptable." Proposed § 122.21(r)(10) distinguishes between "facility level compliance costs" (which the facility may submit if it chooses, but which the permit writer apparently is not obliged to consider) and "social costs," indicating that social costs do not mean total costs. The rule indicates that social costs would include "outages, downtime, and other impacts to facility revenue," as well as costs of additional facility modifications necessary to support construction of the technology, and costs of addressing any non-water quality impacts. Thus, the proposal suggests that the cost component of the cost-benefit evaluation would not necessarily focus on the total capital and O&M costs of compliance. Therefore, IDEM will determine EM BTA for Petersburg based on the information provided pursuant to 122.21(r)(2)-(12). This allowance for broad interpretation could lead to IDEM requiring Closed-Cycle Cooling Tower ("CCCT") at Petersburg for both Units 1 and 2.
4. **Monitoring.** The monitoring required to demonstrate compliance (§ 125.96) may be extremely burdensome and expensive. The monitoring requirements (in § 125.96) are hard to summarize because they differ depending on which compliance option the facility is using. For instance, monitoring for the impingement mortality requirement for existing units depends on whether you are meeting the 12%/31% impingement mortality standard or the 0.5 ft/sec velocity standard. It is unclear if latent mortality or simple enumeration monitoring will be required to demonstrate compliance with the proposed IM BTA requirements. Monitoring for entrainment mortality at new units depends on whether you are meeting the "commensurate with closed-cycle cooling" standard or the 90% standard. For the case-by-case entrainment mortality requirements at existing facilities, the monitoring section of the rule (§125.96) doesn't even specify requirements. But the "reporting" section (§ 125.97(a)(3)) says that the permitting agency will determine what reporting requirements are necessary.
5. **Permit Application Requirements ("PAR").** It is unclear how the state agency will handle the PAR in lieu of the retirement of units expected by the end of 2015.

Comments have been submitted to EPA in order to clarify this and other questions regarding the proposed rule.

6. **Dry Cooling.** Closed-cycle systems are defined to include either wet or dry towers. Hence, under the "case-by-case" approach for entrainment mortality requirements, a permit writer might possibly require dry towers, after considering the nine "factors."

7. **No Entrapment.** The rule requires that fish not be trapped in the intake canal or forebay; they must be able to find their way back to the source waterbody, or else they must be treated as having suffered impingement mortality. The rule is unclear on how a facility is expected to meet this requirement.

8. **Cooling Ponds/Discharge Canals.** Although EPA says that it does not intend to change the regulatory status of cooling ponds (which includes discharge canals), the proposed rule is likely to do just that. Cooling ponds qualify as "closed-cycle recirculating cooling systems" so long as they are not "waters of the U.S." and do not rely on continuous withdrawals (§ 125.92). In the case of Petersburg, the discharge canal has not been designated as Waters of the U.S. ("WOUS") by IDEM in the draft NPDES permit. If this determination changes, it appears the rule would apply to Units 3 and 4.

9. **Unit Retirement.** The proposed rule contains no exemption or site-specific alternative if the facility commits to unit(s) and/or plant retirement.

10. **Other Options.** Besides the proposed rule (called "Option 1"), EPA is considering Options 2, 3, and 4. Option 2 would impose the proposed rule's impingement mortality measures on existing facilities with flow above 2 MGD and the equivalent of closed-cycle cooling on existing facilities with flow above 125 MGD and new units. Option 3 is the same as Option 2, except it would impose the equivalent of closed-cycle cooling on existing facilities with flow above 2 MGD and new units. Option 4 would impose the proposed rule's impingement mortality measures on all facilities with flows of 50 MGD or more and would use best professional judgment for impingement at facilities with flow above 2 MGD but below 50 MGD. Also, Option 4 would require site-specific measures for entrainment at all facilities except new units, which would have to meet the proposed rule's closed-cycle based entrainment requirements. EPA calculates Options 2 and 3 to be far more expensive than the proposed rule, but says Option 4 would be somewhat less expensive.

11. **Compliance Due Date.** Though §125.93 indicates that IM BTA must be achieved "as soon as possible", EPA indicated compliance with the proposed IM BTA should occur no later than eight years from the final effective date of the rule but prefer compliance in the current permit term. However, both IM and EM BTA compliance schedules will be established by IDEM.

12. **Cost of the Rule.** EPA calculates that the total annualized benefits and costs of the proposed rule are $383.8 million for the costs and only $18 million in benefits plus non-monetized benefits. EPA thinks non-monetized benefits may be "significant", making the disparity between costs and benefits less than the 21-to-1 ratio suggests. Elsewhere EPA did not select closed-cycle cooling as IM BTA because it costs more than 10 times as much as modified traveling screens with a fish return system.

13. **Cost-Benefit Analysis.** The proposed rule contains no exemption or site-specific alternative based on cost-benefit analysis, though entrainment mortality

requirements are set case-by-case after "consideration" of "social" costs and benefits (along with eight other "factors").

14. **Benefit Valuation Analysis.** The APEX team did not perform a non-monetized benefit analysis as this term is not clearly defined in the proposed rule and in most cases cannot be monetized as indicated by EPA's own analysis in the proposed rule. However, the APEX team assessed benefits based on the reduction of IM and EM (AQIM: Appendix B).
15. **Lack of Detailed Engineering Study.** The APEX team did not perform a detailed engineering study to assess technical design and economic feasibility of the feasible I&E M options presented in this report. Upon promulgation of the final rule, IPL will re-assess the report's recommendations. At that time, IPL will need to hire an engineering firm to perform detailed engineering and cost assessments for the feasible options.
16. **Compliance Costs.** Cost estimates for 316(b) compliance are plus or minus 40%.
17. **Proposed Rule Versus Final Rule**. The final Section 316(b) rule will likely differ significantly from the one published in April, 2011. In the three previous 316(b) rulemaking efforts, all of the final rules differed substantially from their respective proposals. In two of these rulemaking efforts, the entire basis of compliance as well as the procedures to be followed and some of the key regulatory thresholds were changed. IPL sees strong evidence that similar changes are likely to occur with the current proposed rule. The nature of the changes between the proposed and final rule are very difficult to predict, making the proposed rule the only one available for the purposes of planning.

APPENDIX B: AQIM

Instructions for Completing AQIM Template

The AQIM Template is designed to be a guide for consistently gathering data for measuring the impact of the APEX teams solutions. The template is designed to accommodate financial and non-financial measures of success/impact.

Instructions are provided below as a guide for each line in the template. Each situation is different so the user should use judgement in compiling impact data. Amounts should be entered in the local currency of the business and it is anticipated that they will be in some cases approximate as full implementation and checking may not be complete.
The third tab in this workbook provides space for explanatory notes in support of the data provided and should be used to clarify the data.
This template is intended to capture/consolidate all of the costs and economic benefits from the APEX program for each business. We encourage, however, to distribute it to each team for them to use to follow up their own results.
Please, be sure not to double count any economic benefits reported to groups such as work, asset, revenue management or others.

Frequently Ask Questions

For how long should financial benefits be reported on a project?

Sometimes a project may result in savings than can be carried over the years. However, as a "rule of thumb", to avoid carrying results over a many years, financial benefits on APEX projects must only be reported for a period of 12 months from the moment that benefits start being reported.

What projects should be reported?

Only those projects that have a completed planning phase (that have completed the execution plan) and that are ready to execute shall be included in this template.

When should projects use this template?

All project charters must have a financial evaluation & projection prior to being executed (this template may be used as reference), specially those intended to impact the budget.

When the project's goal is not intended to impact the budget, if it may incur on any costs additional to those budgeted as fixed costs (e.g. overtime that was not budgeted, hiring an external contractor), these costs shall be recorded.

Who should validate the financial results?

Any financial benefits' report must be revised with the business local performance group or finance person, and approved the Business Leader or VP prior to being sent for consolidation to the APEX Regional group or the APEX Global Support Group.

Template Instructions

- **The "Total" sheet shall serve to consolidate the sum of all the "Project" sheets**
- **You may add as many "Project" sheets as you may need**

The "Project" sheet has hidden columns for your use to track the monthly results

Project Summary

X1	Name of the project or brief description of it
X2	Project objectives
X3	Team Leader
X4	Functional Area that would benefit from the project results (for example: Legal department, Finance, Accounting, Maintenance, Operations, Commercial)

Implementation costs

A	Estimate any additional costs of labor of the project team (costs that were not budgeted for the project, e.g. overtime, transportation, and training) used in any phase in the development of the project (OPEX or CAPEX)
B	Estimate the cost of a project team member and other labor required (e.g. contractor services) at any phase of the project EXTERNAL to AES
C	Estimate any additional costs in materials, supplies or equipment used in any phase of the project (OPEX or CAPEX)
D	Estimate any other costs (OPEX or CAPEX)

ECONOMIC BENEFITS RECEIVED AND TRACEABLE FROM BUDGET LINE ITEMS (e.g. lines reported in comshare)
Cash & Revenue Measures (pre-tax) benefits

G	Record or estimate the new/additional revenue generated by the team(s) solution(s) that is not the result of reduced fraud and theft (non-technical losses). Examples would include new charges, new products/services/offtakes, etc.

H	Where applicable, record increases to revenue created by solutions that reduce fraud and theft (This may be the positive variance between the current year's target vs. the current year's actual, or the positive variance between last year's actual vs. the current year's actual) <Be sure not to double count with any revenue, asset, or work management initiative that are reported to this working groups>
I	Increases to revenue from the implementation of more effective collection techniques for delinquent accounts <Be sure not to double count with any revenue, asset, or work management initiative>
J	This refers to increase in cash other than energy sales, or new customer integration to the network. It refers to revenues not associated directly with main operation of the business. For example, 5'S' projects may bring cash from sale of scrap materials, vehicles, non-repairable assets (eg. meters, transformers, etc.), recycle paper, etc.

Cost Measures

L	Reductions in OPEX (Operations and maintentance, or general and administrative costs)
M	Any reduction in CAPEX that has brought benefits to the business

ECONOMIC BENEFITS FROM PROJECT(S) WHICH ARE NOT DIRECTLY TRACEABLE IN THE BUDGET

N	Many times the econmic benefits cannot be directly traceable in budget line items (e.g. comshare lines), yet the projects have provided either increased revenues, or cost reductions (such as: overtime, or avoided penalties from reduced equipment failures) which have been of benefit to the business.

QUALITATIVE BENEFITS

O	This area provides space for teams to define and provide measurement data for any improvements in cycle time created by the solution - e.g., reduced customer waiting times, speed of new service connections, fuels acquisition and delivery cycle, etc.
P	This area provides space for teams to define and provide measurement data for any service quality/reliability measures affected by their solution

Project #	Description	NET Benefits YTD (Include 2010 only)	Forecast	2016 IM Reduction (# fish/year)	2016 EM Reduction (# fish/ year)	2019 IM Reduction (# fish/year)	2019 EM Reduction (# fish/ year)
TOTAL	**Name of Business**						
Project 1	Eagle Valley	No financial benefit	No financial benefit	NA	NA	NA	NA
Project 2	Harding Street	No financial benefit	No financial benefit	2931	2534	2931	2534
Project 3	Petersburg	No financial benefit	No financial benefit	0	0	37026	0
Total				2931	2534	39957	0

NOTES:
NA: Due to plant shutdown; therefore, no longer subject to rule
Based on 2008 I&EM Study
Estimates only; I&EM reduction for HS based on CCCT reductions of 95% for HS U7
PETE assumed 88% survival rate for Impingement based on proposed rule; no additional reduction in EM

Template for Developing and Recording
APEX Quality Improvement Metrics - Total

Business Background Information	Instructions & Notes	Results For			Notes
Business Name		Name of Business			
Total number of employees					
If Generation business - Total MW					
If Distribution business - Total # of clients					
Local business Champion					
				Objective	Notes
Implementation Costs					No costs until after 2011 - mandatory regulatatory requirements
OPEX	**A**				
Labor costs					
Overtime		#REF!	#REF!		
Training		#REF!	#REF!		
Transportation		#REF!	#REF!		
Contracted	**B**				
Contracted Services		#REF!	#REF!		
Professional Services		#REF!	#REF!		
Materials and supplies	**C**				
Materials for operations		#REF!	#REF!		
Office supplies		#REF!	#REF!		
Equipment		#REF!	#REF!		
Various	**D**				
Technology		#REF!	#REF!		
Communications		#REF!	#REF!		
Travel		#REF!	#REF!		
Other costs		#REF!	#REF!		
CAPEX (ACTUAL)					
Labor costs	**A**				
Overtime		#REF!	#REF!		
Training		#REF!	#REF!		
Transportation		#REF!	#REF!		
Contracted	**B**				
Contracted Services		#REF!	#REF!		
Professional Services		#REF!	#REF!		
Materials and supplies	**C**				
Materials for operations		#REF!	#REF!		
Office supplies		#REF!	#REF!		
Equipment		#REF!	#REF!		
Various	**D**				
Technology		#REF!	#REF!		
Communications		#REF!	#REF!		
Travel		#REF!	#REF!		
Other costs		#REF!	#REF!		
TOTAL COSTS		***#REF!***	***#REF!***	***0***	
				Objective	Notes
Cash & Revenue Measures (pre-tax)					No financial benefits
New Revenue Generated (Sales)	**G**	#REF!		#REF!	
Increased revenue from reduction in losses (non-technical)	**H**	#REF!		#REF!	
Reduced Write-Offs	**I**	#REF!		#REF!	
Increased cash from non-operational income	**J**	#REF!		#REF!	
Others	**F**	#REF!		#REF!	
Total Cash & Revenue measures		***#REF!***	***0***	***#REF!***	
Cost Measures					
Reduced Labor Content (e.g. overtime)	**L**	#REF!		#REF!	
Reduced Penalties	**L**	#REF!		#REF!	
Reduced Materials and Supplies	**L**	#REF!		#REF!	
Reduced CAPEX	**M**	#REF!		#REF!	
Others	**F**	#REF!		#REF!	
Total Cost measures		***#REF!***	***0***	***#REF!***	

Template for Developing and Recording
APEX Quality Improvement Metrics - Total

[illegible] not [illegible]	[illegible]	[illegible]	[illegible]	Objective	Notes
Avoided labor costs	**N**	#REF!			No economic benefits
Avoided penalties	**N**	#REF!			
Other revenues	**N**	#REF!			
Other cost reductions	**N**	#REF!			
Total calculated benefits		***#REF!***	***0***	***0***	
TOTAL BENEFITS		**#REF!**	**0**	**#REF!**	

[illegible]	[illegible]	[illegible]	[illegible]	Objective	Notes
Implementation costs (from A)		#REF!	#REF!	0	N/A
Budget benefits (from B)		#REF!	0	#REF!	
Avoided costs (from C)		#REF!	0	0	
Net		**#REF!**	**#REF!**	**#REF!**	

[illegible]	[illegible]	[illegible]	[illegible]	Objective	Notes
Reduced Impingment Mortality (tons/year)	**P**	37026.00	39957.00	Comply with I&E M BTA	
Reduced Entrainment Mortality (tons/year)	**P**	0.00	2993.45	Comply with I&E M BTA	

Template for Developing and Recording
APEX Quality Improvement Metrics - EV

Project Description	**X1**	316(b) Control Strategy			
Objective	**X2**	Comply with proposed 316(b) BTA standards			
Team Leader	**X3**	Jennifer Hatfield			
Functional Area (ex: legal, operations, maintenance, financ…)	**X4**	Environmental			
Business name		**Eagle Valley**			
Local business Champion		**Dewayne Boyer**			
				Objective	**Notes**
Implementation Costs					No costs until after 2011 - mandatory regulatatory requirements
OPEX	**A**				
Labor costs					
Overtime		0			
Training		0			
Transportation		0			
Contracted	**B**				
Contracted Services		0			
Professional Services		0			
Materials and supplies	**C**				
Materials for operations		0			
Office supplies		0			
Equipment		0			
Various	**D**				
Technology		0			
Communications		0			
Travel		0			
Other costs		0			
CAPEX					
Labor costs	**A**				
Overtime		0			
Training		0			
Transportation		0			
Contracted	**B**				
Contracted Services		0			
Professional Services		0			
Materials and supplies	**C**				
Materials for operations		0			
Office supplies		0			
Equipment		0			
Various	**D**				
Technology		0			
Communications		0			
Travel		0			
Other costs		0			
TOTAL COSTS		***0***	***0***	***0***	
				Objective	**Notes**
Cash & Revenue Measures (pre-tax)					No financial benefits
New Revenue Generated (Sales)	**G**	0			
Increased revenue from reduction in losses (non-technical)	**H**	0			
Reduced Write-Offs	**I**	0			
Increased cash from non-operational income	**J**	0			
Others	**F**	0			
Total Cash & Revenue measures		***0***	***0***	***0***	
Cost Measures					
Reduced Labor Content (e.g. overtime)	**L**	0			
Reduced Penalties	**L**	0			
Reduced Materials and Supplies	**L**	0			
Reduced CAPEX	**M**	0			
Others	**F**	0			
Total Cost measures		***0***	***0***	***0***	

Template for Developing and Recording
APEX Quality Improvement Metrics - EV

[illegible] **not** [illegible]		[illegible]	[illegible]	Objective	Notes
Avoided labor costs	**N**	0			No economic benefits
Avoided penalties	**N**	0			
Other revenues	**N**	0			
Other cost reductions	**N**	0			
Total calculated benefits		***0***	***0***	***0***	
TOTAL BENEFITS		**0**	**0**	**0**	
[illegible]		[illegible]	[illegible]	Objective	Notes
Implementation costs (from A)		0	0	0	N/A
Budget benefits (from B)		0	0	0	
Avoided costs (from C)		0	0	0	
Net		**0**	**0**	**0**	

[illegible]		[illegible]	[illegible]	Objective	Notes
Reduced Impingment Mortality (tons/year)	**P**	NA	NA	Comply with I&E M BTA	
Reduced Entrainment Mortality (tons/year)	**P**	NA	NA	Comply with I&E M BTA	

Template for Developing and Recording
APEX Quality Improvement Metrics - HS

Project Description	X1	316(b) Preliminary Compliance Strategy			
Objective	X2	Comply with proposed 316(b) BTA standards			
Team Leader	X3	Jennifer Hatfield			
Functional Area (ex: legal, operations, maintenance, financ…)	X4	Environmental			
		Corporate			
Business name		**Environmental**			
Local business Champion		**Greg Daeger**			
				Objective	Notes
Implementation Costs					No costs until after 2011 - mandatory regulatatory requirements
OPEX	**A**				
Labor costs					
Overtime		0			
Training		0			
Transportation		0			
Contracted	**B**				
Contracted Services		0			
Professional Services		0			
Materials and supplies	***C***				
Materials for operations		0			
Office supplies		0			
Equipment		0			
Various	**D**				
Technology		0			
Communications		0			
Travel		0			
Other costs		0			
CAPEX					
Labor costs	**A**				
Overtime		0			
Training		0			
Transportation		0			
Contracted	**B**				
Contracted Services		0			
Professional Services		0			
Materials and supplies	***C***				
Materials for operations		0			
Office supplies		0			
Equipment		0			
Various	**D**				
Technology		0			
Communications		0			
Travel		0			
Other costs		0			
TOTAL COSTS		***0***	***0***	***0***	
				Objective	Notes
Cash & Revenue Measures (pre-tax)					No financial benefits
New Revenue Generated (Sales)	**G**	0			
Increased revenue from reduction in losses (non-technical)	**H**	0			
Reduced Write-Offs	**I**	0			
Increased cash from non-operational income	**J**	0			
Others	**F**	0			
Total Cash & Revenue measures		***0***	***0***	***0***	
Cost Measures					
Reduced Labor Content (e.g. overtime)	**L**	0			
Reduced Penalties	**L**	0			
Reduced Materials and Supplies	**L**	0			
Reduced CAPEX	**M**	0			
Others	**F**	0			
Total Cost measures		***0***	***0***	***0***	

Template for Developing and Recording
APEX Quality Improvement Metrics - HS

[illegible] not [illegible]		[illegible]	[illegible]	Objective	Notes
Avoided labor costs	N	0			No economic benefits
Avoided penalties	N	0			
Other revenues	N	0			
Other cost reductions	N	0			
Total calculated benefits		*0*	*0*	*0*	
TOTAL BENEFITS		**0**	**0**	**0**	
[illegible]		[illegible]	[illegible]	**Objective**	**Notes**
Implementation costs (from A)		0	0	0	N/A
Budget benefits (from B)		0	0	0	
Avoided costs (from C)		0	0	0	
Net		**0**	**0**	**0**	

[illegible]		[illegible]	[illegible]	Objective	Notes
Reduced Impingment Mortality (tons/year)	P	0.00	2931.00	Comply with I&E M BTA	
Reduced Entrainment Mortality (tons/year)	P	0.00	2993.45	Comply with I&E M BTA	

Template for Developing and Recording
APEX Quality Improvement Metrics - Pete

[illegible]	[illegible]	[illegible]			[illegible]
Project Description	X1	316(b) Control Strategy			
Objective	X2	Comply with proposed 316(b) BTA standards			
Team Leader	X3	Jeff Harter			
Functional Area (ex: legal, operations, maintenance, financ…)	X4	Environmental			
Business name		**Petersburg**			
Local business Champion		**Jeff Harter**			
[illegible]	[illegible]	[illegible]	[illegible]	Objective	Notes
Implementation Costs					No costs until after 2011 - mandatory regulatatory requirements
OPEX	A				
Labor costs					
Overtime		0			
Training		0			
Transportation		0			
Contracted	B				
Contracted Services		0			
Professional Services		0			
Materials and supplies	C				
Materials for operations		0			
Office supplies		0			
Equipment		0			
Various	D				
Technology		0			
Communications		0			
Travel		0			
Other costs		0			
CAPEX					
Labor costs	A				
Overtime		0			
Training		0			
Transportation		0			
Contracted	B				
Contracted Services		0			
Professional Services		0			
Materials and supplies	C				
Materials for operations		0			
Office supplies		0			
Equipment		0			
Various	D				
Technology		0			
Communications		0			
Travel		0			
Other costs		0			
TOTAL COSTS		*0*	*0*	*0*	
[illegible]	[illegible]	[illegible]	[illegible]	Objective	Notes
Cash & Revenue Measures (pre-tax)					No financial benefits
New Revenue Generated (Sales)	G	0			
Increased revenue from reduction in losses (non-technical)	H	0			
Reduced Write-Offs	I	0			
Increased cash from non-operational income	J	0			
Others	F	0			
Total Cash & Revenue measures		*0*	*0*	*0*	
Cost Measures					
Reduced Labor Content (e.g. overtime)	L	0			
Reduced Penalties	L	0			
Reduced Materials and Supplies	L	0			
Reduced CAPEX	M	0			
Others	F	0			
Total Cost measures		*0*	*0*	*0*	

Template for Developing and Recording
APEX Quality Improvement Metrics - Pete

not				Objective	Notes
Avoided labor costs	N	0			No economic benefits
Avoided penalties	N	0			
Other revenues	N	0			
Other cost reductions	N	0			
Total calculated benefits		*0*	*0*	*0*	
TOTAL BENEFITS		**0**	**0**	**0**	
				Objective	**Notes**
Implementation costs (from A)		0	0	0	N/A
Budget benefits (from B)		0	0	0	
Avoided costs (from C)		0	0	0	
Net		**0**	**0**	**0**	

				Objective	Notes
Reduced Impingment Mortality (tons/year)	P	37026.00	37026.00	Comply with I&E M BTA	
Reduced Entrainment Mortality (tons/year)	P	0.00	0.00	Comply with I&E M BTA	

Explanatory Notes as Needed to Accompany AQIM Template

Please provide explanatory notes supporting the template data describing rational, estimation method, nature of the measure, etc. A person who is uninformed about the team's activities but knowledgable of AES business should understand the solution impact claimed and the estimate of its impact.

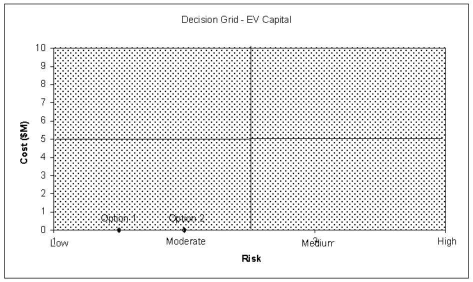
NOTES:
NA: Due to plant shutdown; therefore, EV no longer subject to rule post 2015
I&EM reductions based on 2008 I&EM Study
Percent reductions are estimated values only; monitoring studies will determine true reduction values
PETE assumed 88% survival rate for Impingement based on proposed rule; no additional EM reduction
HS I&EM reduction based on CCCT reduction of 95% for HS U7

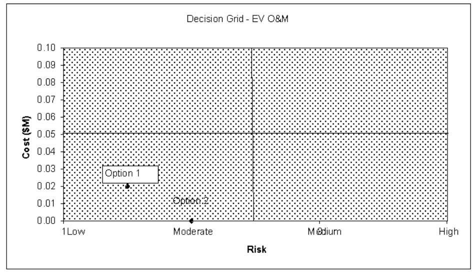
APPENDIX C: APEX Compliance Strategy Plant Options

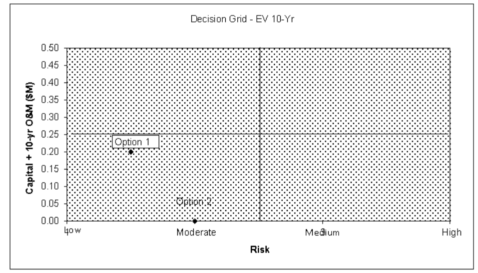
Appendix C - IPL Eagle Valley Station 316(b) Decision Grid

		Costs ($M)		
EV	Risk	Capital	O&M	10-yr
Option 1	1.5	0	0.02	0.20
Option 2	2	0	0	0

Risk = Probability of non-compliance and/or agency disapproval
4=high
3=medium
2=moderate
1=low



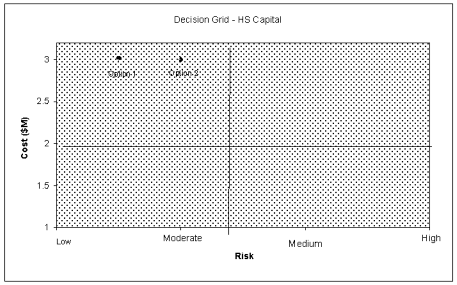


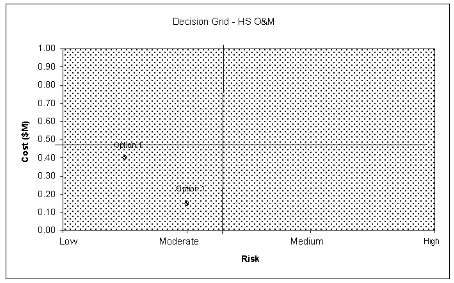


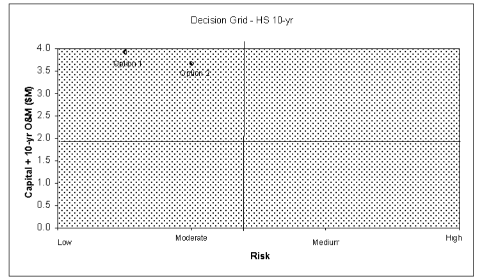
Appendix C - IPL Harding Street Station Decision Grid

		Costs (M$)		
HS	Risk	Capital	O&M	10-yr
Option 1	1.5	3.02	0.40	3.9
Option 2	2	3	0.15	3.7

Risk = Probability of non-compliance and/or agency disapproval
4=high
3=medium
2=moderate
1=low



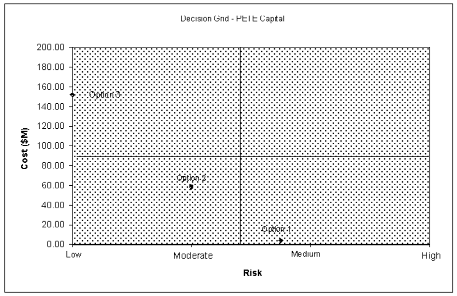


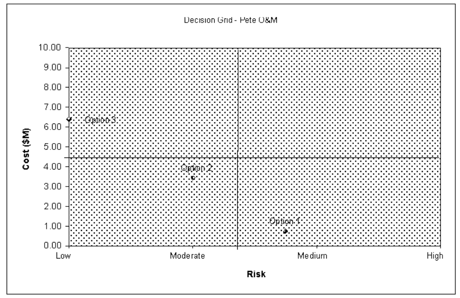


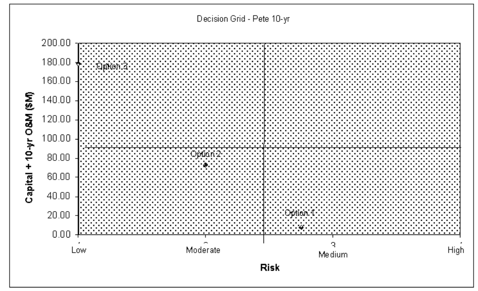
Appendix C - IPL Petersburg Generating Station Decision Grid

		Costs (M$)		
Petersburg	Risk	Capital	O&M	10-yr
Option 1	2.75	3.03	0.74	7.79
Option 2	2	58.53	3.44	72.99
Option 3	1	151.93	6.39	178.24

Probability of non-compliance and/or agency disapproval
4=high
3=medium
2=moderate
1=low







APPENDIX D: AECOM 316(b) Compliance Strategy Plan

AECOM

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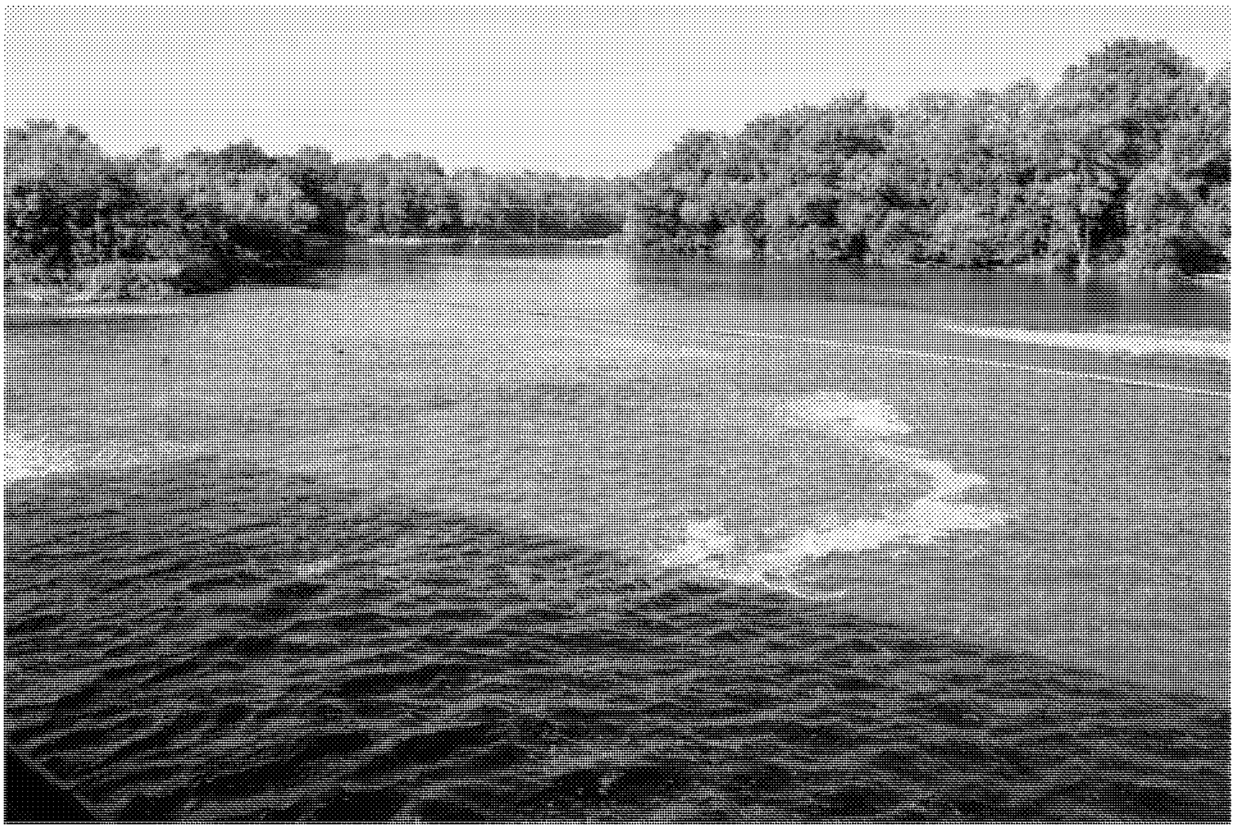
January 2012

316(b) Compliance Strategy Plan Indianapolis Power & Light



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316(b) Compliance Strategy Plan Indianapolis Power & Light

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Contents

List of Appendices

List of Tables

List of Figures

Executive Summary

On April 20, 2011, the United States Environmental Protection Agency (EPA) published a draft version of the 316(b) rule that will regulate existing power generation facilities. The draft rule, in its current form, would have major impacts on the configurations of cooling water intakes for IPL's facilities. A final rule is expected to be signed by July 27, 2012 which will likely include specific timelines for compliance with the rule. Given the potential significant cost implications for compliance with the draft rule, a preliminary assessment of the potential costs have comply with the draft rule was developed in order for IPL to comply with this regulation in the specified timeframe.

The primary objective of the study was to assess the alternatives to comply with the proposed 316(b) rule and to develop preliminary estimates of compliance costs for planning purposes. In addition, strategies for complying with the rule were considered. Compliance with the proposed rule was considered for three facilities based on the following plans for Unit retirements:

- Eagle Valley Units 1-6 to be retired by the end of 2015;
- Harding Street Units 3-6 to be retired by the end of 2015; and
- Petersburg Units 1-4 and Harding Street Unit 7 will remain in current operational status.

For each of these facilities, AECOM considered alternatives for reducing impingement mortality (IM) and entrainment mortality (EM) if appropriate for the station, the potential that those alternatives would achieve compliance/regulatory approval with the proposed rule as written, and the estimated capital and O&M costs associated with those alternatives with potential to achieve compliance. In addition, we estimated the approximate costs of the monitoring and reporting required by the proposed rule. All costs are rough order of magnitude (ROM) costs based on a screening level assessment including a total contingency of 40% on capital costs. These costs are intended to be used for planning efforts. Site specific factors not considered could potentially make actual costs substantially different than those provided here.

It is important to recognize that this document is based on the measures necessary to comply with the proposed rule as written. This rule has a number of problems and based, on previous 316(b) rulemakings and discussions with EPA, we believe the final rule is likely to be substantially different than the proposed rule. The problems with the proposed rule make it a challenge to clearly define alternatives that can be confidently determined to achieve compliance in some situations. In addition, the proposed rule provides the Director significant discretion in determining what measures are appropriate for a given facility. As a result, it is difficult to determine with confidence what measure will be required. Despite these challenges, we have provided the most likely requirements based on available information. These recommendations are made for planning purposes and should not be considered implementable at this time. IPL should develop an implementable compliance plan after finalization of the rule.

AECOM did not consider the impacts of new units or repowering options on the 316(b) compliance requirements as these options are beyond the scope of this effort.

The following table presents the recommended compliance path for each station and the paragraphs that follow summarize the compliance approach for the three IPL stations. While this is AECOM's recommended strategy, we recommend that IPL consider a financial plan that accommodates the higher cost outcomes presented in Section 6.

Recommended Compliance Strategy Summary

Station	Units	Cooling Water Intake Structures	Impingement Mortality BTA	Entrainment Mortality BTA	Monitoring	Permit Application Requirements	Capital Costs[1] ($M)	O&M Costs ($M)	Costs Accrued over 10-yr[1] ($M)	Complete installation
Eagle Valley	1-6	1	Unit 1-6 Retirement/No longer utilize CWIS for CW purposes	Unit 1-6 Retirement/No longer utilize CWIS for CW purposes	NA	IDEM Agreed Order[2]	NA		NA	NA
Harding Street[3]	3, 4	1	Shut down	Shut down	NA	NA	NA		NA	NA
	5,6	2	MTS, FH&RS; reduce velocity to <0.5 fps by installing lower capacity pumps and expanding CWIS bays	Meet EM by being fully closed cycle	Weekly Visual Inspections of MTS and FH&RS; One year of IM monitoring, 4 years of reduced scope monitoring No EM monitoring	122.21(r) (1)-(8)	$3.02	$0.25 (in 2014), $0.15 (2018 onward)	$3.87	2018
	7	NA[4]	NA	NA	NA	NA	NA		NA	NA
Petersburg	1	1	MTS, FH&RS; meet numeric IM standards; remove sensitive forage species from “species of concern”	Existing conditions are BTA for EM, based on cost: monetized benefit imbalance and other environmental and practicality factors	Weekly Visual Inspections of MTS and FH&RS; 5 years of biweekly IM and EM monitoring	122.21(r) (1)-(12)	$3.93	$0.59	$7.60	2014
	2		Same	Same	Same					
	3, 4	NA[5]	NA	NA	NA	NA	NA		NA	NA
						Total	**$6.95**	**$0.74**	**$11.47**	

[1] Capital costs shown in the tables above include equipment, engineering, materials, labor and permitting. O&M includes equipment O&M and annual monitoring costs. Ten-year costs in the table include Capital + O&M.

[2] IPL will need to enter into an Agreed Order with IDEM committing to the retirement of units 1-6 no later than February 2013.

[3] HS path includes retirement of Units 3-6; Utilization of HS CWIS 2 for HS Unit 7 make-up water (2 pumps @ 16,000 gpm each)

[4] Based on the definitions of “cooling water intake structure”, B&T believes the 316(b) regulated “cooling water intake structure” would extend only from the point water is removed from the White River up to the intake pumps in CWIS 2. B&T believes the pipes past that point up to and including the junction box and the intake pumps for Unit 7 would be part of the in-plant water distribution system. However, even if the government were to conclude that the “cooling water intake structure” extended up to and including the Unit 7 intake pumps during this time period, the proposed technical requirements that would apply to the cooling water intake structure likely would be implemented at CWIS 1&2 circulating water pump house and not further downstream at the Unit 7 intake pumps.

[5] At this time, the Petersburg discharge canal has been treated under their NPDES permit as point sources and the water contained in the discharge canal has been treated as a process wastewater subject to the requirements in their NPDES permit at the point that wastewater is discharged from the discharge canal into the receiving water body. Therefore, the discharge canal is not currently considered waters of the United States and removing water from the discharge canal would not be considered withdrawing cooling water from a water of the United States as required in the definition of “cooling water intake structure” in the proposed rule.

Eagle Valley Station: Eagle Valley will be retired before the proposed rule's requirements to reduce IM are in effect (2020). Therefore, Eagle Valley is unlikely to be required to modify its intake. The Proposed Rule's requirements for submitting reports will be in effect prior to the planned retirement of this facility. Therefore, Indiana Department of Environmental Management (IDEM) should be informed of the planned closures in Fall of 2012 and a modification of the NPDES permit requested to relieve the plant of the permit application requirements included in the rule. This request should include a corresponding Agreed Order committing to a closure date for the station which should be issued no later than February 2013. AECOM's recommended compliance path, schedule and cost for Eagle Valley Station are presented in **Table 6.1**.

Harding Street Station: The proposed rule will require the installation of modified traveling screens on cooling water intake structures that will remain in service after unit closures (Units 3-6). We understand that cooling water intake structure for Units 5 and 6 (CWIS 5&6) will remain in service to provide water to the junction box which provides both Unit 7 CCC make-up water and ash sluice water to the plant and anticipate that this intake will be modified to reduce the intake velocity to less than 0.5 fps following the retirements of Units 5 and 6. Based on these changes, the intake would be compliant with the proposed Rule's requirements for reducing impingement mortality without demonstrating achievement of the proposed Rule's IM performance standards. The submittals required by the Rule for Facilities with actual intake flow (AIF) of < 125 MGD would also be required. The estimated cost of compliance for Harding Street Station is summarized in tabular form, including the estimated year of occurrence, in **Table 6.2**. Aggregated costs are expressed on a Net Present Value basis.

Petersburg Generating Station: There is potential that the implementation of the Proposed Rule could require Petersburg to convert one or both units to closed cycle cooling. However, AECOM does not believe this is the most likely outcome based on the historical implementation of 316(b) requirements in Indiana and across the country. Requiring closed cycle cooling on existing steam electric facilities for 316(b) reasons has occurred, however only rarely. Therefore, AECOM believes that the most likely outcome is that the IDEM would require the installation of modified traveling screens and a fish return. This is also supported by the very high cost : monetized benefit ratios (preliminarily estimated as at least 800:1) associated with retrofit to closed cycle cooling.

The proposed rule requires the achievement of IM limitations. This would be challenging or infeasible if the limitations are applied to all species encountered at the facility. However, we recommend advocating to IDEM that the standards should only be applied to species of concern and that those species of concern should not include the sensitive forage fish encountered at the facility (i.e. gizzard shad). If this is successful, there is a potential the facility would achieve the IM limitations in the rule. However, given the high variability in survival following impingement this outcome is not certain. For this reason, the anticipated timing of IPL's response to IDEM should provide the ability to shift compliance strategy should relatively simple IM control measures be insufficient.

Under the proposed Rule, IDEM has significant discretion in determining what is Best Technology Available (BTA) for minimizing EM. Therefore, there is some potential that one or both of the once-through units at Petersburg would be required to convert to closed-cycle cooling. This risk could be increased by IDEM concerns about thermal discharges. Also, there is some small risk that that inability to achieve the IM limitations would lead to the requirement to retrofit to closed cycle cooling in order to reduce the intake velocity to less than 0.5 fps. Therefore, we have estimated the cost of converting one or both units. These costs are likely to be useful for advocating that minimal benefits of closed-cycle cooling do not justify their very high expense.

The estimated cost of compliance for Petersburg Generating Station is summarized in tabular form, including the estimated year of occurrence, in **Table 6.3**. Aggregated costs are expressed on a Net Present Value basis.

Based on this review, AECOM recommends that IPL re-visit the compliance strategy outlined in this document after finalization of the rule. AECOM does not consider this compliance strategy to be an implementable plan as we anticipate significant changes to the Rule. This should include the broad goals (e.g., optimal outcome of the process) as well as important steps within the process (e.g., addressing critical questions with IDEM; goals, methods, and timing of monitoring studies).

AECOM believes that outreach to IDEM following the release of the final rule will be very important. Such outreach might be used to: (1) highlight and resolve critical resource constraints such as the availability of peer reviewers; (2) resolve confusion regarding the implementation schedule and study goals; (3) introduce IPL's proposed compliance approach and advocate for its merits; and (4) discuss the basis for gizzard shad and other sensitive forage species be considered not species of concern. IPL may consider discussing with IDEM the potential to better integrate the considerations of controls aimed at impingement with those intended to mitigate entrainment.

1.0 Introduction

This document describes potential options for compliance at three of Indianapolis Power & Light's (IPL's) generating stations: Eagle Valley, Harding Street, and Petersburg, discusses the likelihood of each option being acceptable, and discusses strategies to comply with 316(b) as cost-effectively as possible. At the request of IPL, AECOM has generally assumed that the proposed 316(b) rule will become effective in 2012 without substantial changes. The circumstances at each plant, including IPL's future plans, have been considered in identifying a set of options to comply the proposed rule. Each of the relevant options is discussed and planning level costs for the option are presented.

AECOM notes that final approval of the compliance approach will be made with the approval of Indiana Department of Environmental Management (IDEM) and review by the United States Environmental Protection Agency (EPA). For this reason, it is difficult to predict the outcome of the 316(b) process at each plant. In particular, more cost-effective options favored by IPL, may not be acceptable to IDEM. Despite this, at two plants, AECOM believes that the likely compliance option is relatively clear. At the third plant, Petersburg Generating Station, it is difficult to predict which option is most likely to be acceptable to IDEM and three options are considered and ranked relative to the cost impact to IPL. In addition, this document outlines a potential approach for maximizing the potential that a favorable compliance option is acceptable.

The proposed rule calls for several regulatory submittals or permit application requirements during the course of implementation. These submittals are described including the proposed rule's schedule requirements as well as planning level cost estimates for each required report.

The balance of this section will summarize the proposed 316(b) rule, will discuss the potential for the proposal to change as it becomes a final rule, and review the organization of the report.

1.1 Summary of the Proposed Rule

EPA published its proposed rule to regulate cooling water intake structures (CWIS) at existing facilities on April 20, 2011, and subsequently extended the 90-day comment period until August 18, 2011. Despite the extension in the public comment period, the rule is scheduled to be finalized in July 2012 and will include several implementation milestones. The proposed rule would set requirements that establish Best Technology Available (BTA) for minimizing adverse environmental impact from CWIS from impingement mortality (IM) and entrainment mortality (EM). Impingement mortality results from impingement of aquatic organisms on the cooling water intake structure, typically traveling water screens used to prevent debris from entering the cooling water circulating pumps and the steam condenser tubes. Entrainment mortality results when organisms that are entrained through the cooling water intake structure die due to the combined effects of mechanical stress from the pumps, thermal stresses from the heat transferred from the condensers, and application of biocides.

Based on its experience with the previous 316(b) rulemaking processes as well as its knowledge of the ongoing negotiations between EPA and the regulated community, AECOM anticipates that the final rule will differ in many ways from the proposal. Because it is impossible to predict the nature of those changes at this time, AECOM will use the proposed rule as the basis for its discussion of the likely impacts to IPL's three generating plants. When appropriate, the uncertainty in this assumption will be discussed. AECOM has also included a discussion of its general strategic approach to compliance with the 316(b) Rule including consideration that the rule that will be promulgated in 2012 is likely to differ substantially from the proposal of 2011.

This Draft Compliance Plan was prepared based on the current draft rule as published in April 2011. The intent of this plan is to provide IPL with a preliminary compliance strategy and timeline for permitting and estimated compliance and capital and maintenance costs that could be incurred to achieve compliance with the draft rule as currently published, for planning purposes. This plan will be revisited after publication of the final rule.

A Technical Memorandum, included in **Appendix A**, was prepared to consolidate existing and planned conditions at IPL's Petersburg Generating Station, Harding Street Station, and Eagle Valley Station with regard to the draft 316(b) rule. The Technical Memorandum is intended to provide a summary of technical considerations that were used to develop this Compliance Plan for efficient 316(b) compliance at IPL's generating fleet for the next several years.

It was recently announced that all of the units at the Eagle Valley Station and the four oldest units at the Harding Street Station are to be retired or otherwise taken out of service in the next several years. These anticipated operational changes were taken into consideration when developing this compliance plan and in some cases, the potential compliance path will affect the decision for future operational considerations.

1.2 316(b) Rule Requirements Applicable to IPL

Section 316(b) of the Clean Water Act requires that NPDES permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. Specifically, the 316(b) Rule is intended to reduce the impacts from withdrawal of cooling water by facilities to aquatic organisms through impingement and entrainment.

The rule defines separate paths toward compliance for impingement and for entrainment. The separate paths also have different timelines and imply separate review and action by IDEM. The draft rule compliance paths are represented in **Figure 1**.

1.2.1 Impingement

The rule requires that all facilities with existing traveling screens retrofit them with "fish-friendly" Ristroph modifications, consisting of smooth screen mesh, fish buckets installed at the base of each screen panel, low-pressure washes for fish located before the high pressure wash for debris, separate collection troughs for fish and debris, and a fish return system. Continuous rotation of the traveling screens is not required by the proposed rule but AECOM believes that it is highly advisable in the event that numerical impingement mortality standards are relevant to the site (see below).

The intake velocity then dictates the path for compliance with the impingement mortality portion of the rule. For facilities with traveling screens, intake velocity is generally interpreted to be equivalent to the through-screen velocity; otherwise it is the velocity at the point of withdrawal. AECOM notes, however, that "intake velocity" is not among the specialized definitions in the proposed rule and the term is not always used in an unambiguous manner. Facilities that can demonstrate that design intake velocities are equal to or less than 0.5 feet per second (fps) are not subject to the numeric impingement mortality performance standards and are not required to conduct impingement mortality monitoring. They must however operate and maintain their intake screen such that less than 15 percent of the surface area is occluded by debris, and they must ensure that impingeable fish have the means to escape or be returned to the source waterbody (e.g., a fish return). Facilities that cannot demonstrate that the design intake velocity meets this threshold must conduct compliance monitoring for intake velocity to demonstrate the intake velocity is consistent with the requirements of § 125.94(b)(2). IDEM will determine the details associated with IM monitoring after their review of the IM Reduction Plans (mid-2016) and will render the final IM BTA requirements via the NPDES permit.

Under the proposed rule, facilities that have through-screen velocities in excess of 0.5 fps must conduct bi-weekly impingement monitoring, at a minimum, and are required to achieve impingement mortality rates of less than 12 percent on an annual basis and less than 31 percent on a monthly basis. Proposed Section 125.96(c) also requires facilities to perform visual or remote inspections of the CWIS at least weekly to ensure the technologies installed are meeting the BTA requirements and conduct monitoring of impingement rates on a monthly basis. EPA has indicated that the numerical impingement mortality performance standards apply only to “species of concern”; however the regulatory language does not clearly indicate this. AECOM believes that these performance standards are seriously flawed and will create significant compliance concerns at many facilities. They have drawn much attention during the public comment period and may not be included in the final rule.

1.2.2 Entrainment

Under the proposed rule, facilities that are equipped with closed cycle cooling, including wet or dry cooling towers or closed loop cooling ponds, are considered to be BTA for entrainment. Facilities not so equipped must determine if their actual intake flow is greater than 125 MGD. Under the proposed rule, facilities that have withdrawn an average of over 125 MGD over the last three years would have to prepare four documents evaluating the feasibility, costs, and benefits of potential measures to reduce entrainment and entrainment mortality. These facilities will be required to conduct entrainment mortality monitoring. The scope, frequency, or schedule for monitoring is not defined in the proposed regulation and is therefore left to the discretion of the NPDES Director. The proposed rule does not have a blanket requirement to mitigate entrainment but leaves the decision to require such measures to the permitting authority (i.e., IDEM). The studies required for facilities with actual intake flows greater than 125 MGD are described in **Section 3.0** of this report.

The proposed rule would require that at least two technologies (closed cycle cooling and the use of fine mesh panels on the traveling screens) be evaluated for cost, effectiveness, and monetized benefit. The Entrainment Characterization Study must be submitted to IDEM for review and approval. Under the proposed rule, each of the studies also requires peer review by a third party. Based on the findings of these four studies, the permitting authority establishes BTA on a case-by-case basis. Facilities with actual intake flows less than 125 MGD are not required to perform the studies but are still subject to a BTA determination on a Best Professional Judgment basis by IDEM. Under the proposed rule, new units placed into service at existing facilities would be required to reduce entrainment mortality to levels commensurate with the use of closed cycle cooling. AECOM believes that retrofit with closed cycle cooling at an existing facility will be very expensive and result in a very adverse cost-to-monetized benefit ratios. However, the EPA has proposed this rule with an apparent cost/monetized-benefit ratio of approximately 21:1 was cost effective, therefore unless retrofit costs are shown to be significantly higher than anticipated benefits cost alone may not be sufficient to guarantee elimination of an option. Achieving levels of entrainment mortality reduction commensurate with closed cycle cooling using other technologies will be very difficult and in many cases infeasible.

1.3 Potential for Changes between the Proposed and Final Rule

The final Section 316(b) rule will likely differ significantly from the one published in April, 2011. In the three previous 316(b) rulemaking efforts, all of the final rules differed substantially from their respective proposals. In two of these rulemaking efforts, the entire basis of compliance as well as the procedures to be followed and some of the key regulatory thresholds were changed. AECOM sees strong evidence that similar changes are likely to occur with the current proposed rule. Firstly, AECOM believes that the proposed rule was drafted in a hurried fashion and that EPA intended the regulatory language (i.e., the proposed changes to the 40 CFR) to include more flexibility than it did. This is illustrated by several inconsistencies between the regulatory language and the proposed rule's preamble as well as supporting documents that clearly suggest that other compliance options should be considered for impingement. Secondly, EPA's extension of the public comment period on the draft rule was in part due to negotiations between EPA and stakeholders that may result in substantial changes in the final rule (which may or may not limit the potential for further litigation). AECOM understands that these discussions have continued and have included very specific proposals to change the rule. EPA has expressed sympathy with many of these changes including the potential to include alternative compliance measures including those focused on reducing impingement as distinct from impingement mortality, remove the requirements to meet a maximum rate of impingement mortality, and, potentially, definition of Ristroph-type retrofits as a "pre-approved" technology that would require little or no monitoring of impingement mortality. EPA is also considering the inclusion of a feasibility/economic variance from the impingement mortality BTA requirements but only if it believed that such a variance would be only applied at a small subset of plants. AECOM believes that several aspects of the proposed rule are likely to be retained in the final rule, including: (1) the requirement that most plants meet a minimum common standard of engineering retrofit such as modified Ristroph screens; (2) the requirement to develop several permit related reports; (3) some level of operational monitoring of the mitigation technologies; and (4) the requirement for peer review for some of the regulatory submittals.

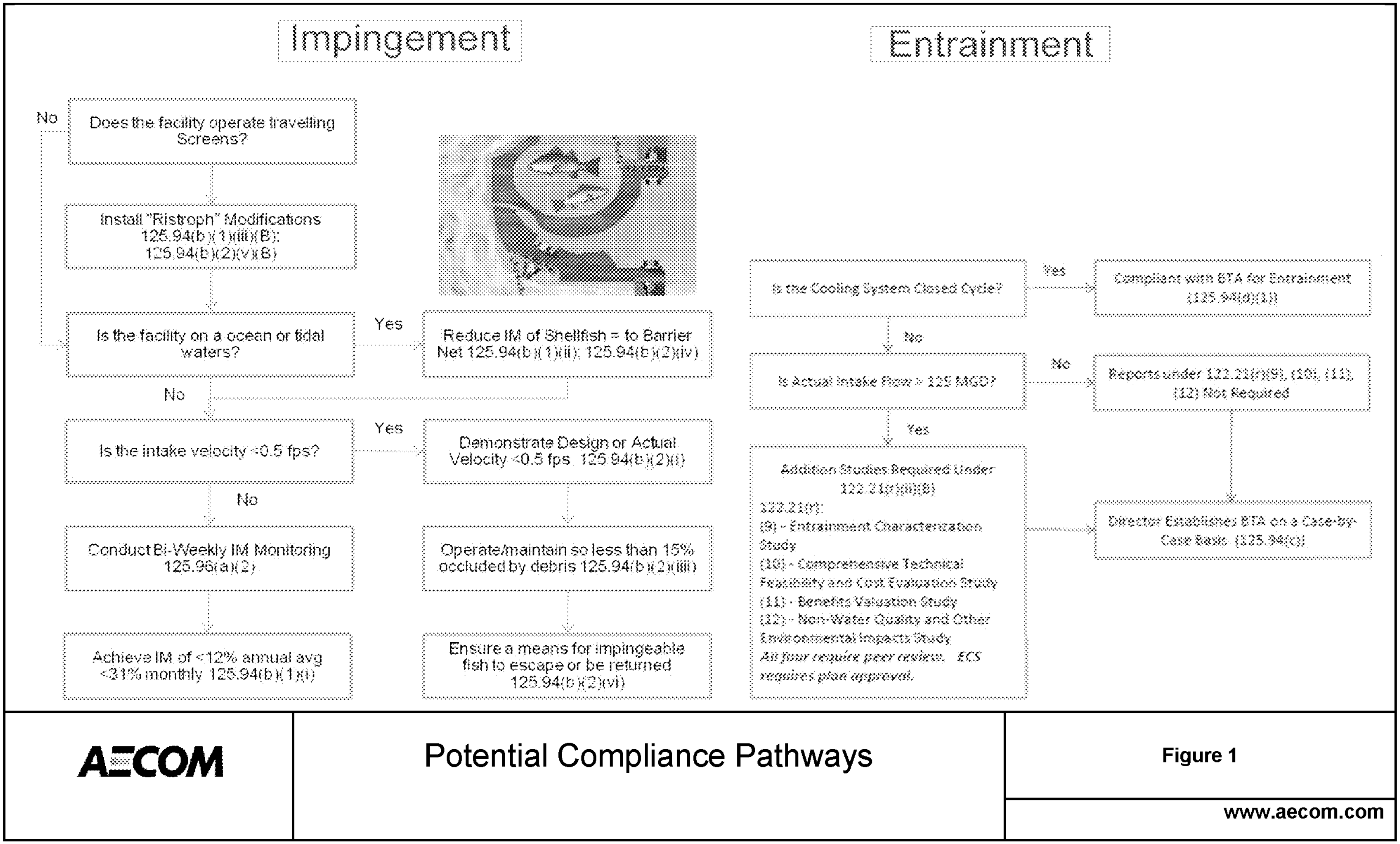
The nature of the changes between the proposed and final rule are very difficult to predict, making the proposed rule the only one available for the purposes of planning. While the majority of this report is organized around this assumption, AECOM has also included a section discussing a recommended strategy for the next year to anticipate and potentially improve the outcome of the final rule.

1.4 Document Organization

The balance of this document is organized into the following sections:

- **Section 2** describes the three stations including their cooling water intake structures, mode of cooling, available biological data, and IPL's plans for future operation;
- The Permit Application Requirements spelled out in 40 CFR 122.21(r) are defined in **Section 3;**
- **Section 4** reviews the impingement mortality and entrainment mortality mitigation measures allowed by the proposed rule and considered in this evaluation;
- **Section 5** reviews the compliance options available at each of the three plants and defines the ones that are most likely to be required for planning purposes; and
- A summary of AECOM's recommended strategies is presented in **Section 6**.

Figure 1 316(b) Draft Rule Compliance Path



2.0 Existing Conditions/Future Plans

This section presents a brief summary of the conditions at each of the three plants. Additional information is available in the Technical Memorandum presented in **Appendix A.**

2.1 Eagle Valley Station

2.1.1 Current Conditions

Eagle Valley Station currently operates six generating units with total generating capacity of 364 MW. The six units draw once-through cooling water from the West Fork of the White River through three cooling water intake structures that have a combined design intake flow rate (DIF) of 335.4 million gallons per day (MGD), average intake flow rate (AIF) of 156.2 MGD. The three separate CWIS are equipped with rotating traveling screens intake technology. Design intake velocities are 0.77 feet per second (fps), 1.07 fps, and 1.24 fps at the three CWIS. Under the current operating conditions, the Eagle Valley Station would be subject to both impingement and entrainment requirements of the draft rule.

2.1.2 Planned Conditions

Units 1 through 6 at Eagle Valley Station are slated for retirement by the end of 2015. After retirement, there will be no operating cooling water intakes at the facility. After the facility retirement, 316(b) rule requirements will not apply to the station. However, compliance actions under Section 316(b) may still be required for Eagle Valley pre-2015 and are discussed in **Section 3.1**.

2.2 Harding Street Station

2.2.1 Current Conditions

Harding Street Station currently operates five generating units with total generating capacity of 1,196 MW. Four of the units draw once-through cooling water through two cooling water intake structures that have a combined DIF of 238.8 MGD, AIF of 108.2 MGD, and design intake velocities of 0.97 fps and 1.17 fps at Units 3 and 4, and Units 5 and 6 CWIS, respectively. Both CWISs are located on the West Fork of the White River and employ rotating traveling screens intake technology. Unit 7 operates with closed cycle cooling. Under the current operating conditions, the Harding Street Station would be subject to impingement requirements of the draft rule, and could be subject to entrainment requirements, though due to AIF being less than 125 MGD, evaluation of entrainment BTA would be on a best professional judgment basis.

2.2.2 Planned Conditions

Units 3through 6 are scheduled to be retired by 2015. . After retirement of Units 3-6, water will be drawn through CWIS 5&6 to provide makeup water for the Unit 7 cooling tower and other plant needs. IPL may delay the submission regarding commitment of unit retirement to IDEM.

2.3 Petersburg Generating Station

Petersburg Station operates four coal-fired generating units with total generating capacity of 1,725 MW. Two units, 1 and 2 draw once-through cooling water through one cooling water intake structure that has a combined DIF of 427.7 MGD, AIF of 383.4 MGD, and design intake velocities of 1.60 fps and 1.32 fps through Units 1 and 2 bays, respectively. The CWIS for Units 1 and 2 is located on the White River and employs rotating traveling screens CWIS technology. Unit 2 employs closed cycle cooling in the form of evaporative cooling towers to dissipate approximately one-half of the waste heat generated by the unit. Some of the remaining infrastructure necessary to complete the conversion of Unit 2 to closed cycle cooling is in place. Units 3 and 4 operate with closed cycle cooling. Makeup water for the cooling towers employed by Units 3 and 4 is provided through the discharge of Units 1 and 2 condensers. Under the current operating conditions, the Petersburg Station would be subject to both the impingement and entrainment requirements of the draft rule for the CWIS associated with Units 1 and 2.

The Petersburg Generating Station is not scheduled for operational modifications at this time.

3.0 Permit Application Requirements

The draft rule requires submittal of a series of reports from existing facilities on a defined schedule. The reporting requirements are described in general below and in more detail in Sections 4 and 5 of the attached Technical Memorandum.

- **122.21(r)(2) - Source water physical data.** - Maps and description of source water. Area influence of intake. Required of all existing facilities. Due 6 months after finalization of the rule.
- **122.21(r)(3) - Cooling water intake structure data. -** Engineering drawings, water balance, summary of operation and position. Required of all existing facilities. Due 6 months after finalization of the rule.
- **122.21(r)(4) - Source water baseline biological characterization data.** Summary of taxa subject to impingement and entrainment including seasonal variation and listed species. Document public participation and data gaps. List existing protective measures. Cost estimate is based on the assumption that existing data are used and no field work is necessary. The applicability of this requirement is not consistently stated in the draft rule. One portion of the draft rule indicates that it will only be required for "new facilities", while another portion suggests that it is required for all facilities. The assumption has been made that it is required for IPL facilities for this planning document. Due 6 months after finalization of the rule.
- **122.21(r)(5) - Cooling water system data.** Narrative description of the cooling system including any water reuse or water reduction. Days of operation and proportion of source water withdrawn. List of existing protective measures and a summary of their performance. Not required at facilities with closed cycle cooling, if facilities have CCC at the time of the application submittal. Due 6 months after finalization of the rule.
- **122.21(r)(6) - Impingement mortality reduction plan.** Define approach used to meet impingement mortality performance goals. Include nature of performance monitoring including identification of species of concern and methods for evaluating latent mortality (if appropriate). Required of all existing facilities. Due 6 months after finalization of the rule. AECOM notes that, as defined in the proposed rule, this plan will be developed relatively early in the compliance effort and changes in the approach to monitoring and technology installation/operation may be necessary as the effort proceeds. This should be reflected in the plan and in discussions with IDEM.
- **122.21(r)(7) - Performance studies.** Summary of biological data that were conducted in the past or at other facilities. Not required at facilities with closed cycle cooling. Due 6 months after finalization of the rule.
- **122.21(r)(8) - Operational status.** Description of the operational status of each "generation, production, or process unit". Include rates of production for the last five years and anticipated production plans. Not required at facilities with closed cycle cooling. Due 6 months after finalization of the rule.
- **122.21(r)(9) - Entrainment characterization study.** Plan to characterize entrainment mortality including duration, frequency, and location of monitoring. Identification of species of

concern, QA/QC measures, and methods for characterizing latent mortality. Provide peer review. Required only if AIF > 125 MGD. Due 6 months after finalization of the rule. As with the impingement mortality reduction plan, this effort will require several strategic decisions relative to the monitoring program etc. The plan should be crafted to include flexibility.

- **122.21(r)(10) - Comprehensive technical feasibility and cost evaluation study.** Evaluation of the technical feasibility and costs of entrainment control technologies. Must include evaluation of closed cycle cooling and addition of fine mesh screens. Peer review is required. Required only if AIF > 125 MGD. Due 5 years after finalization of the rule.
- **122.21(r)(11) - Benefits valuation study.** Evaluation of the magnitude of monetized and non-monetized benefits of potential impingement mortality and entrainment control measures. Peer review is required. Required only if AIF > 125 MGD. Due 5 years after finalization of the rule.
- **122.21(r)(12) - Non-water quality and other environmental impacts study.** Site-specific discussion of changes in non-water quality factors and other environmental impacts associated with each technology and measure considered under (r) 10. Peer review is required. Required only if AIF > 125 MGD. Due 5 years after finalization of the rule.

Some of this information was submitted previously by IPL in 2008 and, with minor modifications, will suffice for submittal under the new rule. The general applicability to each IPL plant is presented in **Section 3.2**.

3.1 Monitoring Requirements

The proposed 316(b) regulation contains significant requirements for entrainment and impingement monitoring. These requirements are vaguely defined by the regulation and in some cases there is contradictory language on their content and applicability. Under the proposed rule the Director has substantial discretion over the frequency, duration, and nature of both IM and EM monitoring. As a result, there is a wide range of requirements that may be applied to IPL's facilities. In this section we present potential monitoring requirements based on review of the rule and agency precedent; actual monitoring requirements may be substantially different.

3.1.1 Impingement Mortality Monitoring Requirements

The rule requires monitoring of impingement rates at all facilities and monitoring to demonstrate the effectiveness of the technology at reducing IM when the intake velocity if >0.5 fps. The frequency and duration of the monitoring of IM is not clearly defined in the rule. For facilities with intake velocities of <0.5 fps, the rule requires either a demonstration that the maximum design velocity is less than this value or monitoring of the actual intake velocity on a biweekly basis.

The rule is unclear as to when the monitoring must start or how long it must continue. Submittal of the IM study results is required 3.5 years after finalization of the rule. This suggests that the impingement mortality monitoring required by the impingement mortality reduction plan must be completed by that time. However, the installation of technology for reducing IM is not required to be complete until 8 years after finalization. It is not clear how this discrepancy will be resolved in the final rule or interpreted by IDEM. This discrepancy has been considered, and a strategy to resolve developed, in the planning of strategy and estimation of costs for the IPL facilities.

In order to evaluate the approximate costs associated with the IM monitoring, AECOM has assumed that monitoring at Harding Street will occur once within the time frame necessary to provide results to

IDEM by the due date 3.5 years after finalization of the rule, or March 2016. This monitoring will occur biweekly with 12 monitoring events consisting of latent mortality monitoring; the remaining 14 monitoring events consisting of enumeration only. Monitoring would be designed to collect specimens at the effluent from the screens, identify naturally moribund individuals and species of concern and will account for episodic events. We have estimated that this monitoring would cost approximately $250,000 per year. We have assumed that enumeration-only monitoring would be required as a condition of the station's NPDES permit after installation of the modified traveling screen system and has estimated a cost of approximately $100,000 for this monitoring (2019 forward).

At Petersburg we have assumed that IM monitoring would begin shortly after installation of modified traveling screens (2015) and within the time frame necessary to provide the first year's results to IDEM by the due date of March 2016. We have also assumed that IM monitoring would continue each of the following four years of the NPDES permit period (5 yr total). This monitoring would occur biweekly consisting of 12 monitoring events of latent mortality monitoring; the remaining 14 monitoring events consisting of enumeration only each year. For costing purposes, AECOM has assumed this monitoring would occur for five years after installation of the modified traveling screens system. Monitoring costs were estimated at $250,000 per year.

3.1.2 Entrainment Mortality Monitoring Requirements

The proposed rule requires the development of an entrainment mortality data collection plan. This plan is likely to require conditions for some entrainment monitoring. However, the rule does not contain and specific requirements governing the frequency, nature, or duration of entrainment monitoring. Therefore, it is difficult to accurately predict the costs associated with any entrainment monitoring that will be required. To estimate potential costs, AECOM has made a number of assumptions.

The draft Entrainment Characterization Study is required to be submitted with peer reviewer identified within six months of finalization of the rule. The peer reviewed plan is required to be submitted six months after that and the EM study to be completed within 4 years. AECOM has assumed that monitoring will begin at the Petersburg Generating Station after submittal and acceptance of the peer reviewed Entrainment Characterization Study and will be conducted and reported the next year within the required four-year period (2013). Additional monitoring is not planned again until after the Director has rendered a BTA determination. Entrainment monitoring is not expected to be required at the Harding Street Station.

For the purposes of estimating the potential costs, AECOM has assumed that entrainment monitoring would consist of enumeration only. Monitoring would occur biweekly concurrent with impingement sampling. If sampling is not concurrent with impingement sampling, costs would increase substantially. Monitoring costs were estimated at $150,000 per year.

3.2 Individual Station PAR Requirements

The following is a summary of the reporting requirements for each station. All dates are based on assumption that the final rule will be published in July 2012 and become final 60 days after publication. AECOM estimated costs for each plant for completing these requirements and conducting studies are included in the compliance schedule in **Section 5.0**.

Eagle Valley Station

IPL has studied the compliance options available to Eagle Valley Station considering the plans to close the plant by the end of 2015. Options are described in the memorandum prepared by Barnes & Thornburg included in Appendix C of the Technical Memo. The options considered include:

- Submit all documents required by the 316(b) rule and inform IDEM of closure plans as part of this submittal process;
- Inform IDEM of closure and request relief from submittal requirements by committing to closure dates without NPDES permit modification (Barnes & Thornburg (B&T) determined this option to not be feasible; therefore this option will not be considered further);
- Inform IDEM of closure and request modification of NPDES permit to relieve plant of submittal requirements by committing to closure dates with a corresponding Agreed Order; or
- Request a variance from the 316(b) requirements based on hardship (B&T determined this option to not be feasible; therefore this option will not be considered further).

AECOM recommends informing IDEM of the planned closures and requesting modification of the NPDES permit to relieve the plant of the permit application requirements included in the rule with a corresponding Agreed Order committing to a closure date for the station. In this case, no additional reporting will be required.

In each of these cases, AECOM assumes that IDEM will not require retrofit and operation of new technologies to mitigate either impingement mortality or entrainment mortality. This conclusion is based on the fact that the proposed rule would not require retrofits until after the plant closure and that any retrofits would have a very poor cost-to-benefit ratio based on an operational period of only a year or two. While AECOM believes that this is a sensible outcome, we do note that IDEM will have to approve the approach.

Harding Street Station

Similar to the Eagle Valley Station options, IPL may consider requesting relief from some aspects of the 316(b) rule for the Harding Street Station due to plans to close portions of the plant within the NPDES permit period. However, because the Harding Street Station will continue to operate Unit 7 and will continue to operate one of the existing CWISs to provide water to Unit 7 and other plant needs, the station will be required to submit applicable reports and plans. The reporting options for Harding Street are discussed in the Barnes & Thornburg memo in Appendix C of the Technical Memo. These options include:

- Submit all documents required by the 316(b) rule and inform IDEM of closure plans as part of this submittal process;

- Inform IDEM of closure and request modification of NPDES permit to relieve plant of some of the submittal requirements by committing to closure dates via Agreed Order; or
- Request a variance from the 316(b) requirements based on hardship (B&T determined this option to not be feasible; therefore this option will not be considered further).

AECOM recommends that IPL proceed by submitting the documents required by 316(b) rule and inform IDEM of closure plans after submittal process (March 2016). The permit application requirements presented below are based on the first option.

IPL is anticipating closure of four once-through cooling units at Harding Street. It is assumed that Units 3 through 6 would be closed by the end of 2015. However, AECOM recommends that Harding Street submit applicable information and reports on schedule in order to allow flexibility related to committing to unit retirement with IDEM. The following schedule assumes that Harding Street Station will not commit to unit retirement until after the facility submits the IM reduction Plan which is due six months after finalization of the rule. Because Harding Street Station's average intake flow is less than 125 MGD in its current configuration, the reports required by sections (9), (10), (11), and (12) are not required.

Harding Street				
122.21(r) Section	**Submittal Due Date**	**Previously Submitted**	**Completeness of Previous Data**	**Cost to Prepare Plan/Conduct Study**
(2) Source water physical data	March 2013	Yes	Complete as written	$0
(3) Cooling water intake structure data	March 2013	Yes	Complete as written	$10,000
(4) Source water baseline biological characterization data	March 2013	Yes	Complete as written	$10,000
(5) Cooling water system data	March 2013	Yes	Complete as written	$5,000
(6) Impingement mortality reduction plan	Plan: March 2013 Study: complete by March 2016	No	Will require preparation of plan and completion of study over the following 3.5 years.	Plan: $20,000 Study: $250,000/yr
(7) Performance studies	March 2013	No	Data is in hand. Will require repackaging.	$5,000
(8) Operational status	March 2013	No	This report will summarize HS future plans if finalized.	$5,000
(9) – (12)	Not Required	No	Not required for facilities with AIF < 125 MGD	N/A
Expected Reporting and Study Costs				Reports and Plans: $55,000 IM Study: $250,000/yr

Petersburg Generating Station

The Petersburg Station will continue to operate in current mode until the results of the studies required by the rule determine what technologies would be considered BTA for EM at the facility. Because the station has an AIF greater than 125 MGD, all sections of the reporting requirements apply.

Petersburg				
122.21(r) Section	Submittal Due Date	Previously Submitted	Completeness of Previous Data	Cost to Prepare Plan/Conduct Study
(2) Source water physical data	March 2013	Yes	Complete as written	$0
(3) Cooling water intake structure data	March 2013	Yes	Complete as written	$10,000
(4) Source water baseline biological characterization data	March 2013	Yes	Complete as written	$10,000
(5) Cooling water system data	March 2013	Yes	Complete as written	$5,000
(6) Impingement mortality reduction plan	Plan: March 2013 Study: submit results by March 2016	No	Will require preparation of plan and completion of study over the following 3.5 years.	Plan: $20,000 Study: $250,000/yr
(7) Performance studies	March 2013	No	Data is in hand. Will require repackaging.	$5,000
(8) Operational status	March 2013	No	This report will summarize Petersburg future plans.	$5,000
(9) Entrainment characterization study	Complete draft plan and identify peer reviewer by 3/2013. Submit peer reviewed plan in 9/2013. Submit EM study results by 9/2016.	No	Will require preparation of a full monitoring plan.	Plan: $25,000 Study: $150,000/yr
(10) Comprehensive technical feasibility and cost evaluation study	September 2017	No	New report required.	$50,000
(11) Benefits valuation study	September 2017	No	New report required.	$60,000
(12) Non-water quality and other environmental impacts study	September 2017	No	New report required.	$40,000
Expected Reporting and Study Costs				Reports and Plans: $230,000 Studies: $400,000/yr

4.0 Technologies Considered

The feasibility, costs, and effectiveness of many of the technologies commonly used or studied for use in reducing IM and EM at cooling water intake structures were reviewed for this study. The following sections describe the technologies that were determined to be potentially feasible at the IPL stations for reducing IM and EM. The complete review of other technologies previously considered is presented in Appendix B of the Technical Memorandum, provided in **Appendix A** of this planning document.

4.1 Costing Approach

Rough order of magnitude (ROM) costs were developed based on values from a number of sources and site specific factors. While these cost estimates are based on consideration of a number of site-specific factors, they are still approximate. In many cases, the costs rely on cost equations from the EPA TDD that may be out of date or not applicable. In addition, rapid changes in the price of commodities and energy have the potential to impact the estimates that are presented. Also most of these sources represent the national average costs and do not take into account regional differences in material and labor costs. Therefore, while the costs presented here are useful for considering the relative costs of various alternatives, the actual costs of implementing any of these alternatives could be substantially higher.

Costs were developed based on values from a number of sources and site specific factors. A summary of the approach used to develop the costs is included in this section. The cost estimates for the various technologies were prepared using the following resources:

- EPA Technical Development Document (TDD) for the Final Section 316(b) Phase II Existing Facilities Rule, February 12, 2004. (EPA-821-R-04-007) (EPA 2004a);
- EPA Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Proposed Rule, April 2002. (EPA-821-R-02-003) (EPA 2002);
- Cost estimates and/or installed costs for similar equipment obtained from vendors and other operating plants; and
- Brayton Point Plant 316(b) Demonstration (USGen New England Inc. 2001).

Available costs were adjusted to account for size/capacity differences as follows:

- proportionally for components/equipment whose costs were judged to be proportional to size (e.g. pipe length); and
- by the 6/10ths rule[1] for those components whose costs were judged to not be directly proportional to size (e.g. pumps).

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[1] The 6/10ths rule or factor is a logarithmic relationship between equipment size and cost. In simple form, $Cn = r0.6C$, where Cn = cost of new equipment, C = cost of existing equipment (or a known cost), and r = the ratio of the new to existing capacity or size. [reference: Chilton, C.H., "Six Tenths Factor," *Chemical Engineering*, April 1950, pp. 112-114.]

The following factors were applied, where appropriate:

- 10% Allowance for indeterminates (AFI), a contingency[2] on costs of the items included;
- 30% contingency[2] to address unforeseen items, especially with regard to a plant retrofit; and
- Escalation based on the time frame of the basis cost estimate. Since the basis cost year varied, estimated costs were escalated based on 1.9% annual rate of inflation.

Details of the cost assumptions for each technology are presented below in the applicable sections.

4.2 Modified Traveling (Ristroph) Screens

The draft rule as written requires installation of Ristroph screens with fish return at all existing facilities with traveling screens. Therefore, costs, feasibility, and performance of Ristroph screens were considered for both Harding Street and Petersburg Stations under the proposed 2015 operating conditions.

Overview

This alternative consists of replacing the existing traveling screens with modified Ristroph screens to decrease the mortality of organisms that are impinged. The new screens would include fish buckets on the screens, low and high pressure spray wash systems and separate debris and fish return troughs. The discharge point of the fish return trough would be selected in order to minimize the potential for re-impingement in the intake flow or exposure to the heated discharge. Appendix D of the Technical Memorandum presents depictions of Ristroph screens.

Technical Feasibility

Ristroph screens can typically be installed directly into the slots for standard traveling screens. Therefore, installing Ristroph screens at the IPL facilities would be feasible. It is assumed that full traveling screen hardware replacement would be required at both plants. Traveling screen replacement could likely be accomplished without unit downtime by installing the modified screens during scheduled outages and/or by isolating individual bays for installation and keeping other bays open during replacement.

There could be significant issues with construction and maintenance of fish return troughs at the IPL facilities due to the required length, fluctuations in river level, and freezing conditions. These concerns have potential to make the installation of an effective fish return infeasible or extremely challenging. Despite these concerns, the proposed rule does not contain exceptions to the requirement to install a fish return. A detailed engineering study should be conducted to determine the best design for fish return at the IPL stations.

[2] The 10% AFI and 30% contingency were both chosen based on past experience and engineering judgment for this level of cost estimate.

Predicted Survival Rates with Ristroph Screens

Facilities with intake velocities of greater than 0.5 fps are required to meet impingement mortality limitations of 12% on an annual basis and 31% on a monthly basis. These values correspond to post-impingement survival rates of 88% and 69% respectively. Each of the IPL stations currently has design intake velocity of greater than 0.5 fps, therefore, we estimated the effectiveness of Ristroph screen modifications at both IPL facilities.

Detailed description of the calculation of survival rates summarized here is provided in Section 7.2 of the Technical Memorandum.

Survival following impingement on Ristroph Modified screens varies considerably between species. Some species have survival rates of greater than 90%, while others experience greater than 50% mortality. Therefore, considering the survival of the species potentially impinged at each facility was important when characterizing the effectiveness of the alternatives considered. For example, gizzard shad was the most common fish impinged at the IPL stations in the 2008 impingement study (41% of individuals collected at Harding Street and 68% at Petersburg). Gizzard shad has a low predicted survival rate of 48% which reduces the overall impingement survival rate at the stations.

Based on this review, the facilities are not projected to meet the proposed rule's impingement mortality limitations with the installation of Ristroph screens if all impinged species are considered species of concern. Survival based on this preliminary assessment is estimated to be approximately 55% at each of the facilities. This corresponds to an impingement mortality rate of 45%, well above the draft Rule's IM limitations.

Based on conversations with EPA and information provided in the Technical Development Document, the proposed Rule's impingement mortality limitations are intended to be applied to only species of concern. However, this is not clear in the regulatory text in the proposed rule. There is potential that the final rule will more clearly indicate that any numeric performance standards only apply to species of concern. If this is the case, there is potential that IPL could advocate for excluding gizzard shad from the species of concern. AECOM has estimated that if gizzard shad, threadfin shad and other forage species are removed from consideration in IM survivability rates, the survivability of the hardier species could approach 85% at Petersburg and 90% at Harding Street, which is within the margin of error of the performance goal. It should be noted that these percentages are based on a very small sample size and should be confirmed with additional monitoring data. If IDEM accepts this position, compliance with the performance standard using Ristroph modified screens might be achieved.

E Effectiveness

This alternative would not be effective at reducing E. The Ristroph screens considered under this assessment have standard size mesh. Fine mesh screens are discussed in the following section.

Impingement Monitoring Requirements:

As discussed in **Section 3.1.1**, facilities with intake velocities that exceed 0.5 fps are required to conduct IM and impingement rate monitoring. These requirements would be directly applicable to Ristroph screens. Details of monitoring plans are presented in **Section 3.1**.

Capital and O&M Costs

The total estimated rough order of magnitude (ROM) costs for installing Ristroph modified traveling screens and associated equipment is $1.6MM for installation on 2 screen bays on CWIS 5&6 at Harding Street, and $3.4MM for the six screens bays of Units 1 and 2 CWIS at Petersburg Station. This capital cost includes the cost of replacing traveling screen equipment to accommodate Ristroph modifications, the cost of the Ristroph equipment (screens, buckets, low pressure spray wash pumps), and construction of a fish return trough. The costs assume a relatively simple construction and installation of a 500 ft long fish return at Petersburg and a 600 ft long fish return at Harding Street. AECOM has included an additional 30% to the cost of the fish return to account for heating of the fish return flume to avoid freezing and measures to protect the fish return flume from debris or ice damage. These costs do not account for any modification of the screen wells, screen house, or related structures.

Ristroph screens would impose a higher operating and maintenance cost than the existing traveling screens. These costs are related to the assumption that the modified traveling screens would be rotated continuously whenever the unit is operation. Under current operations, the screens are rotated on an intermittent basis. The increase in rotation frequency leads to increased power use and can lead to more frequent screen and pump rebuilds. Operation and maintenance costs at the Harding Street Station are estimated to be approximately $52,000 per year above the cost of maintaining the current traveling screen system. O&M costs for Petersburg Station are estimated to be $190,000 above the cost of maintaining the current traveling screen system. These costs include the increased power draw associated with additional spray wash pumps and continuous screen rotation and assume that increased costs associated with screen and pump rebuilds would be incurred based on the continual rotation of the screens. Assumptions made in calculating costs are presented in tables below.

Ristroph Cost Estimates for Harding Street Station:

- Capital Costs for Ristroph Screens and 600 ft Fish Return Trough: $1.6MM
  - Costs for Screens and Installation: $1.0 MM
  - Costs for Fish Return Flume: $530,000
  - Capital Costs for Added Low Pressure Spray Wash Pump: $70,000
- Net Screen Operation and Maintenance Costs for Screen and Pump Rebuild and Power Draw:
  - Increase in O&M costs: $52,000/yr
  - Current estimated O&M Costs: $34,000/yr
  - Projected O&M Costs: $86,000/yr

Ristroph Cost Estimates for Petersburg:

- Capital Costs for Ristroph Screens and 500 ft Fish Return Trough: $3.4MM
  - Costs for Screens and Installation: $2.8 MM
  - Costs for Fish Return Flume: $460,000
  - Capital Costs for Added Low Pressure Spray Wash Pump: $140,000

- Net Screen Operation and Maintenance Costs for Screen and Pump Rebuild and Power Draw based on Current Operating Frequency:
  - Increase in O&M costs: $190,000/yr
  - Current estimated O&M Costs: $90,000/yr
  - Projected O&M Costs: $280,000/yr

These costs are based on a very preliminary review of the facility and have significant uncertainty. The assumptions made are outlined in the tables below. A more detailed study may determine that actual costs are significantly higher or lower. The estimated cost of performing a pilot study, if required by IDEM is $200,000 at each facility. It is not certain that a pilot study for the modified traveling screen system would be required, but the costs are included in the units' summary tables in **Section 6**.

Cost Assumptions for Ristroph Screens at Harding Street Station

Parameter	Assumed Value	Notes
Number of days that screens are operated annually	335	Based on ratio of AIF to DIF
Current Screen Rotation Frequency	30 minutes per day	Based on rotating once/shift for 10 min.
Current Screen Rebuild Interval	10 years	Based on BPJ
Current Screen Rebuild Cost	~$62,000 per screen	Based on vendor provided estimated costs of $250/ft^2
Fish Return Trough Cost	$700/linear foot (@500')	Based on vendor provided estimates
Power Cost	$0.04/kw hr	Based on EPA's TDD
Spray Wash Pump Rebuild Interval	4 years	BPJ
Spray Wash Pump Rebuild Cost	Unit 5/6 CWIS: $8,750	Based on vendor input and practices at similar facilities

Cost Assumptions for Ristroph Screens at Petersburg Generating Station

Parameter	Assumed Value	Notes
Number of days that screens are operated annually	329 days	Based on ratio of AIF to DIF
Current Screen Rotation Frequency	4 hrs per day	Based on rotating once/hour for 10 min.
Current Screen Rebuild Interval	10 years	Based on BPJ
Current Screen Rebuild Cost	~$125,000 per screen	Based on vendor provided estimated costs of $250/ft^2
Fish Return Trough Cost	$700/linear foot (@600')	Based on vendor provided estimates
Power Cost	$0.04/kw hr	Based on EPA's TDD
Spray Wash Pump Rebuild Interval	4 years	BPJ
Spray Wash Pump Rebuild Cost	Unit 1: $8,750 Unit 2: $17,500	Based on vendor input and practices at similar facilities

Conclusions

This technology is required by proposed section 125.94(b), therefore it will be required to be installed at both IPL stations. This alternative would be unlikely to meet the proposed rule's impingement mortality numeric limitations for all species impinged. However, there is some potential that the performance relative to the rule's goals would be substantially higher if IDEM concluded that Gizzard Shad and other forage species are not considered species of concern in calculating survival rates. In addition, there is potential that the final rule will be structured to allow facilities that install Ristroph modified screens to be compliant without demonstrating achievement of a numeric performance standard.

4.3 Barrier Nets

Overview

Barrier nets are wide-mesh (generally 1/4 or 3/8 inch) nets that are placed in front of the intake structure entrance to exclude fish. These are typically either strung between pilings or suspended from floats and anchored on the bottom. Organisms are generally able to avoid impingement on the barrier nets due to low through-net velocities (often less than 0.1 fps). Barrier nets in northern climates are typically installed on a seasonal basis. They are frequently installed during peak migration periods and removed during the winter months due to ice damage concerns.

As drafted the proposed rule does not provide credit for the reduction in impingement rates that barrier nets may achieve. This may change as the rule is finalized. Until that happens, AECOM believes that use of barrier nets should not be considered as a means of compliance with the rule. As a result they were not considered further here. Additional discussion of the potential costs and effectiveness of barrier nets is included in the Technical Memorandum for reference.

4.4 Ristroph Screens with Fine Mesh Panels (< 2 mm)

Overview

This alternative consists of replacing adding removable fine mesh panels with 1 mm openings to reduce E to the Ristroph screens that are required by the proposed rule (as described in **Section 4.1** above). Fine mesh panels are considered as measures to potentially reduce EM.

The fine mesh panels would likely be installed on a seasonal basis during periods of high entrainment and removed during periods when clogging or carryover is a concern. The highest E rates measured at the IPL stations during the 2008 E study occurred in summer months. During other times of the year, E rates were very low or zero. Therefore, it has been assumed that the fine mesh panels would be installed during the summer and removed during the rest of the year.

Harding Street Station's average intake flow over the past three years is less than 125 MGD and will only be reduced further with planned future unit retirements. Therefore, the proposed rule's requirements for assessing alternative to reduce entrainment do not apply to Harding Street and this facility is not likely to be required to consider this alternative. Petersburg has an actual intake flow of greater than 125 MGD. Therefore, fine mesh panels were considered for Petersburg.

Technical Feasibility:

The feasibility of fine mesh panels on the Ristroph screens is dependent on the potential for clogging, carryover, and the added head loss associated with the fine mesh screens. Fine mesh screens would result in greater head loss across the screen and higher through screen velocity than standard mesh screens. This has potential to impact pump operations, and therefore this would need to be assessed prior to installing fine mesh screens. In addition, with finer mesh screens there is more potential for the screens to become clogged with debris. If the screen wash system is not effective at removing this debris, there is potential carryover of the debris to the backside of the screen where it has potential to cause clogging or fouling of the condenser and other equipment. In addition, fine mesh screens are more prone to clogging. Clogging of the screens could build up to the extent that head loss across the screen would result in pump cavitation, or even the collapse of the screen. The potential for these factors to limit the application of fine mesh panels is difficult to predict. Therefore, desk top modeling, detailed engineering, and field pilot testing would be required to assess these factors.

IM Effectiveness

Fine mesh traveling screens are primarily utilized to reduce E; on their own they do not offer any known advantages for reducing IM of organisms that are impinged on standard mesh screens[3].

E Effectiveness

E is reduced with fine mesh screens due to physical exclusion of organisms that would otherwise be entrained through standard 3/8 inch mesh screens. As a result, organisms that would be entrained through standard screens may become impinged on fine mesh screens. The effectiveness of such a system at reducing E could be assessed in two ways: 1) based strictly on the exclusion of organisms from the cooling water or 2) based on the survival and return of the excluded organisms to the water body. EPA indicates that the latter approach is relevant in the preamble to the proposed Rule.

More detailed analysis of the entrainment effectiveness for fine mesh panels is presented in Section 7.4 of the Technical Memorandum. Effectiveness of fine mesh panels is based on the exclusion of organisms the screens and the survival of those organisms following contact with the screens. Both of these factors are difficult to predict. The exclusion of organisms is based on in part on the size and life stage of organisms entrained. However, the relationship between these factors is not clearly understood. The studies illustrate that survival is highly variable, depending on life stage, species, intake structure characteristics, and other factors and so is very difficult to predict. Despite these challenges we have roughly predicted that fine mesh panels have the potential to exclude up to 35% of the organisms that would be entrained. However, we have estimated that only approximately 36% of these would survive exclusion and subsequent return to the water body. Therefore, if both exclusion and survival are considered, the total EM performance of this alternative is roughly estimated to be 13%.

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[3] Note the preamble to the proposed rule does list “fine mesh traveling screens with fish return systems” as a technology to reduce impingement mortality. It is not clear why they list this technology in addition to modified traveling screens with a fish return as fine mesh panels have no accepted impact on the mortality of organisms that would have been impinged on standard mesh screens.

Capital Costs and Economic Feasibility

The capital cost for removable fine mesh panels was estimated using parameters from the TDD (USEPA 2004) and the dimensions of the IPL facilities. The estimated capital cost for the screens would be approximately $550,000 for placement on the screens in all six bays in the Unit 1 and 2 CWIS at Petersburg Station. This cost assumes that these screens would be installed on Ristroph traveling screens that are designed to accommodate fine panels as add-ons. Fine mesh panels were not considered for Harding Street as Unit 7 is CCC.

Operation and maintenance costs associated removing, re-installing, and maintaining the fine mesh panels is estimated to cost an additional $140,000/yr over and above the maintenance costs associated with standard Ristroph screens. This cost assumes that the fine mesh screen panels would be installed and removed once per year to accommodate periods of high debris loading and is based on an assumed labor cost of $50/hr. If more frequent removal and replacement of the panels is required the costs would increase substantially. If major debris clogging or biofouling issues are encountered, other substantial costs could be encountered.

Conclusions

While fine mesh panels are potentially feasible, the total EM performance of this alternative is roughly estimated to be 13%. While this estimate is very uncertain, it suggests that this alternative may not be particularly effective at reducing EM. There is significant uncertainty about the amount of debris loading and its effect on this technology considering that historically, the highest levels of entrainment were observed during the months of highest average precipitation and therefore potential quantity of debris in the river (May, June, July and August). Despite this low performance estimate, this alternative may present the best alternative for reducing entrainment at a reasonable cost. If this alternative were to be considered, it would be important to conduct site-specific tests of clogging, carry over, and organisms exclusion and survival prior to implementing this alternative. Fine mesh panels are not considered at this time due to the anticipated low EM reduction success rate.

4.5 Closed Cycle Cooling

Closed Cycle cooling was considered for Petersburg Unit 2 alone (Case 2) and for both Units 1 and 2 (Case 3) (Case 1 being neither unit converting to closed cycle). Currently, Petersburg Generating Station operates Units 1 and 2 with once-through cooling, with a half cooling tower on Unit 2 that is utilized during summer months. Units 3 and 4 at Petersburg are closed cycle.

Retrofit of closed cycle cooling for Harding Street Station was not considered. Under the proposed 2015 operating conditions, Harding Street Station will operate only Unit 7 which is already closed cycle.

Description:

The existing cooling water systems at Petersburg Units 1 and 2 use river water pumped through a steam condenser and discharged back to the source water body. These systems are generally referred to as open cycle or once-through cooling system because the water simply passes through the condenser (no recirculation) where heat is transferred from the steam to the cooling water prior to discharge. Closed cycle systems recirculate the cooling water. Typically, the heated water from the condenser is cooled down in each cycle using evaporative cooling. This cooled water is then recirculated to the condenser to cool and condense the steam from the turbine. In the mechanical draft-cooling tower, fans are used to circulate air that flows against the heated water sprayed inside the tower. Cooled water is collected in the tower basin and returned to the condenser. Water must be introduced into the system at regular intervals to make up for losses due to blowdown and evaporation.

The makeup water flow for a mechanical draft-cooling tower is typically less than 5 percent of the flow required for once-through cooling. The makeup flow would be pumped to the circulating water system from the current intake structure. At Petersburg Station, blowdown is either discharged from the tower basins to the White River through separate NPDES permitted outfalls or to the on-site ash pond system to Lick Creek through a NPDES permitted outfall.

Water needs were determined from the facility water balance diagram and are presented in **Table 4.2-1** in the Technical Memo. Based on the facility water balance diagram, it is estimated that approximately 64,000 gpm (92 MGD), which includes estimates of makeup water for Units 1 and 2 cooling towers, would be needed to operate Petersburg Station with four units on closed cycle cooling. If only Unit 2, which has a one-half-size cooling tower (i.e., it is designed to dissipate one-half of the waste heat generated by Unit 2) is modified to full closed cycle cooling, Unit 1 circ pumps must provide sufficient flow to feed makeup water to cooling towers serving Units 2, 3, and 4 as well as other plant needs. Unit 1 circ pumps have DIF capacity of 112,000 gpm or 161 MGD which is more than sufficient to provide flow to the other three units' makeup water and other plant needs shown in **Table 4.2-1**.

Technical Feasibility and Reliability:

The technology proposed for this alternative is well known and has been implemented for similar power plants. Despite this, only a very small number of power plants using once-through cooling have retrofitted to cooling towers. This alternative requires substantial open space, consumes a substantial amount of electricity, and reduces the thermal efficiency of the system. In addition, the ability of the existing condensers to handle the higher pressures associated with the recirculating system is uncertain and could have a large effect on the costs for this alternative.

Significant site constraints and operational concerns at the Petersburg Generating Station impact the potential to install new cooling tower systems at the facility. Little space is available on site that would be conducive to installation and operation of cooling towers. Towers would have to be placed where drift would not impact existing switchyards and substation equipment. Underground piping from condensers to the cooling tower location would have to be installed under existing boilers and generating units, greatly disrupting plant operations. For cost estimating purposes for this study, AECOM has placed the proposed Unit 1 cooling tower on the northwest side of the site between the existing Units 3 and 4 cooling towers and the river as shown in **Figure 2**. This placement, as well as placement anywhere on the site, presents significant challenges and would involve significant disruption of plant facilities and operations. Despite this, it was used to represent a potential placement of the cooling towers for costing purposes. The cooling tower for Unit 2 was assumed to be an expansion of the existing half cooling tower that is located just east of Units 3 and 4 towers.

Estimated Costs:

The capital costs associated with retrofitting both Petersburg Unit 1 and 2 would be approximately $136MM. The capital costs for installing closed cycle cooling on Unit 2 are estimated to be $45MMThese capital costs are based on the following assumptions:

- A ΔT of 13°F was assumed for the CTs
- The cycles of concentration are 3.0

- Drift rate is 0.001%
- New cooling water pumps are installed with the retrofit to closed cycle cooling

Cooling towers also have significant operating and maintenance costs. These costs are associated with parasitic power consumption and water treatment costs. Each of these values was estimated for both cases and included in the annual O&M costs. In addition, there is likely to be a loss of turbine efficiency associated with the installation of the closed cycle cooling. We utilized the EPA's TDD estimate of 1.0% efficiency loss for fossil fuel plants. Based on our experience the actual efficiency may be lower, therefore this represents a conservative value.

For Case 3, in which both units are converted to CCC, we estimated that the total O& M costs associated with closed cycle cooling are approximately $5.8MM annually. For Case 2, in which only Unit 2 is converted to CCC, we estimate that the total O&M costs are approximately $2.7MM. These costs include routine maintenance of the cooling tower equipment, parasitic power loss and chemical water treatment costs. Annual parasitic power costs due to operation of cooling tower fans and loss of plant efficiency is estimated at approximately $0.8MM for Case 3 and $0.40MM for Case 2. We assumed that the power costs are $0.04/kw-hr.

Finally, installation of cooling towers will require some unit downtime. We have estimated that the project duration of Case 3 would be approximately 15 months. We have assumed that the net downtime would be approximately 5% to 10% of this total project time, or approximately 1 month. Based on the assumption that the Petersburg facility would have been utilized at a 95% rate during this period and the lost revenue is $0.04/kw-hr, we have estimated that this downtime would cost approximately $12MM. Using a similar approach for Case 2, we have estimated that the project duration would be approximately 11 months and the downtime approximately one month. The downtime costs for Case 2 are estimated to be $6.3MM. These estimates represent the worst case, whereas if the plant cooling tower installation and associated down time were to occur during a regularly planned outage, these costs would have already been accounted for in the outage plans.

Capital cost estimate developed by AECOM were compared with costs developed using cost factors based on total cooling water flow presented in EPRI's 2011 Technical Report on Closed Cycle Cooling Retrofit Study. This comparison indicates that the costs for installing closed cycle cooling on both Units 1 and 2 are comparable to the cost derived from the costing factors that are applied to "difficult" to "more difficult" installation of cooling towers by EPRI 2011 (**Figure 3**). Our estimated costs are likely high due to the significant distance between the condenser and the location of the cooling towers. This distance has a substantial impact on costs. The estimated costs for the installation of full closed cycle cooling on Unit 2 only is between that derived with the "easy" and "average" cost factors from EPRI 2011 (**Figure 4**), due in large part to the existence of the half-sized cooling tower for Unit 2. In combination, these comparisons support the capital cost estimates for the two cases considered.

Cost Considerations:

The cooling tower capital costs were developed using a built up approach by component. Each of the components below describes what costs are included in those individual components.

<u>Mechanical:</u>

1. Cooling Tower w/out Basin - Includes complete CT (Base) assemblies delivered & erected; site clearing; excavations etc.

2. Cooling Water and Yard Piping, and Pumps - includes circulating water pumps and circulating water pipe costs.
3. Make-up & Chemical System.
4. Equipment Freight.

Structural and Civil:

1. Cooling Tower Basin & Structure.
2. Cooling Water Intake/Discharge & Structure - Includes circulating water pumphouse and circulation water piping civil & structural capital costs
3. Water Treatment Structural
4. Site & Retrofit Costs - includes roadways costs and site restoration costs

Electrical:

1. Switch Yard, Switch Gear, Transformers
2. Power, Instrumentation and Control
3. Other Electrical Equipment

Other Project Related Cost (estimated as % of the total construction cost)

1. Mobilization/Demobilization, 2-5%
2. Architectural Fees, 8% max.
3. Contractor's Overhead & Profit, 12% Est.
4. Process Engineering, assumed as 12%,
5. Contingency, 10%

Exclusions:

1) Small land purchases in order to locate retrofitted cooling towers or provide access for circulation water system.
2) Expedited construction schedules and need to hire more personnel than a "greenfield" project.
3) Temporary delays in construction schedules due to congestion and inability to work multiple tasks in parallel.
4) Branching or diversion of cooling water systems; reinforcement of retrofitted conduit system connections.
5) Major strengthening modifications or upgrades to the Turbine Building, condenser or existing cooling water pipes.
6) Excessive plant congestion & interferences.

Effectiveness:

The mechanical draft cooling tower alternative reduces intake flow by typically 95% or more. It is assumed that it results in similar reductions in impingement and entrainment. This technology is considered Best Technology Available for entrainment reduction in the 316(b) rule. However, the rule requires closed cycle facilities to implement additional measures to achieve compliance with the IM requirements.

Other Potential Adverse Effects:

Closed cycle cooling systems result in other adverse environmental impacts that may offset the benefit of reduced impingement and entrainment. Operation of closed cycle cooling towers will increase energy consumption by the plant; increase in water effluent temperature, though decreasing volume; increase in air emissions (particulates due to cooling tower drift and overall emissions due to decreased plant efficiency); increase water consumption; increase noise levels; increase safety concerns; and increase the potential impacts to plant and therefore grid reliability.

The primary adverse effects for the mechanical draft cooling tower alternative are associated with increased water vapor content in the immediate area of the cooling towers. This will result in a visible plume for some periods and has the potential to result in fogging impacts. To reduce the potential for these effects, a plume abatement system would be employed. Because cooling tower drift cannot be eliminated completely, the tower would be located as far as possible from electrical equipment, off-site receptors, and sensitive vegetation. Space limitations may make it difficult to locate the cooling towers to minimize these effects. A cooling tower also imposes noise and aesthetic impacts. Another significant environmental effect is that the decrease in efficiency means that more fuel is burned per unit of electrical energy output. Therefore, a plant with cooling towers will have more emissions than a plant utilizing an open cycle system. The increase in emissions will be proportional to the decrease in plant efficiency. We have assumed a 1.0% loss in efficiency for the Petersburg facility based on EPA's TDD document; therefore, we have assumed a 1.0% increase in emissions from the plant.

Costs Relative to Benefits

IPL has commissioned a study by EPRI to estimate the monetized benefits to be realized through installation of full closed cycle cooling at the Petersburg Generating Station (Estimates of the Economic Value of Entrainment and impingement Losses: Facility No. 2201P8E, EPRI, 2011). The study calculated the value of 15 species of fish entrained or impinged during the 2007 IM&E study conducted at the facility. The values were calculated assuming 100% mortality of the entrained and impinged fish. The study determined that the annual economic value of the fish entrained or impinged at the Petersburg Station was $3,274 and that the annual economic benefit of installation of closed cycle cooling would be $3,045.

AECOM has calculated that the cost of installation of cooling towers for Unit 2 alone is over $45,000,000 and the additional cost to operate and maintain the cooling towers for Unit 2 is $2,700,000. This O&M cost alone, not considering the annualized capital cost, amounts to a cost : monetized benefit ratio of over 800:1. Conversion of both Units 1 and 2 to closed cycle is approximately an order of magnitude higher than this. This value clearly illustrates that the costs of converting Petersburg Station to closed cycle cooling far outweigh the benefits to be gained and provides a strong basis for concluding that closed cycle cooling is not BTA for EM. Therefore, a strong case can be made against conversion to closed cycle cooling.

Overall Assessment of Alternative:

EPA considers facilities that have closed cycle cooling to have Best Technology Available for entrainment mortality reduction. IPL is retiring its once-through cooling units Eagle Valley and Harding Street Station Units 3-6 by the end of 2015. Therefore, these facilities will be compliant with entrainment requirements. Converting Petersburg Units 1 and 2 to closed cycle cooling would eventually bring Petersburg into compliance with BTA for entrainment. However, the benefit of achieving compliance must be balanced against the difficulties of fully installing cooling towers for Unit 1, very substantial capital and O&M costs, negative environmental impacts, and operational implications of closed cycle cooling. Therefore, compliance approaches other than closed cycle cooling should be pursued to the extent possible. AECOM's recommendations are provided in **Section 5**.

4.6 Measures to Reduce Intake Velocity

Description

Reducing intake velocity to below 0.5 fps is generally accepted to greatly reduce impingement rates. In addition, it has the benefit of allowing a facility to avoid the need to meet impingement mortality performance standards in the rule. As a result, facilities that choose to reduce their intake velocity have a defined path to complying with the rule's impingement mortality requirements.

Intake velocity can be reduced by reducing intake volume or by increasing the open area of the screens. Flow reductions can be achieved by installing closed cycle cooling, retiring units, operational measures, installing variable speed pumps, or by making other pump modifications. The primary way to increase screen open area is by expanding the intake structure and adding screen wells. It may also be possible to increase open area by installing dual flow screens.

Technical Feasibility and Reliability

At the Petersburg Generating Station under current once-through cooling conditions, intake velocity exceeds 0.5 fps. At current intake velocities, the size of the current intake structures would need to be more than tripled to achieve the desired reduction in velocity. Current intake velocities are 1.60 fps for Unit 1 and 1.32 fps for Unit 2. Therefore, expansion of the intake structures would likely be very costly and may not be feasible. If one or both of Unit 1 or 2 were converted to closed cycle cooling, the reduced cooling water needs could reduce velocity sufficiently so that additional modifications could achieve the 0.5 fps through screen velocity.

At Harding Street Station, current through-screen velocities exceed 0.5 fps at the two CWIS. Future operating conditions involve retirement of Units 3, 4, 5 and 6. Velocity reduction could be met with reduced pumping capacity and CWIS modification.

Modification of CWIS at Petersburg: A modification of the existing CWIS bays has been considered to reduce the through screen velocity below 0.5 fps if Unit 2 was converted to closed cycle cooling. This would be accomplished by creating an opening through the concrete walls separating the individual bays of the CWIS. The openings would be designed to promote equal flow through each of the screens feeding each active pump. In this way, the two Unit 1 pumps would see an increase in available area of three times, resulting in a reduction of velocity by one third to approximately 0.53 fps. In order to increase area sufficiently to reduce velocity the maximum extent possible at Petersburg, openings would be made in five concrete walls between the intake bays on the pump side of the traveling screens. Unit 2 make-up water would be drawn from the discharge canal where its existing cooling tower and the cooling towers for Units 3 and 4 currently draw their makeup water. This option is not considered feasible by Petersburg plant personnel and will not be considered further due to structural stability issues associated with modifying the existing CWIS.

Reduced Intake Capacity at Harding Street: If Units 3, 4, 5 and 6 are retired at the Harding Street facility, the maximum design intake velocity could be reduced to below 0.5 fps by installation of lower capacity pumps and CWIS modification to increase screen area. It has been estimated that one 16,000 gpm pump would be sufficient to provide the necessary flow to Unit 7 for makeup water and other plant needs. Therefore, only one pump will operate at a time with the other pump designated as back up.

Currently, operation of one pump in each intake bay at current design rate of 24,750 gpm produces an intake velocity of 1.17 gpm. Reduction of pump capacity to 16,000 gpm would reduce design intake velocity in each bay to 0.76 fps. In order to further reduce velocity in each bay to less than 0.5 fps, the structure must be modified to increase screen area. This may be accomplished by creating an opening through the concrete wall separating adjacent bays of the CWIS, opening two bays to each pump. In this way, each of the two 16,000 gpm pumps (one active, one backup) would achieve through-screen velocity of 0.38 fps. Therefore, to achieve reduction of design intake velocity at the Harding Street Station, pump capacity must be reduced and the CWIS must be modified. Replacing all four CWIS 5&6 pumps with 10,000 gallon pumps and operating two pumps at all time in the existing bays, would reduce intake velocity to 0.48 and eliminate the need to expand the CWIS. This option would require installation of modified traveling screens on all four intake bays which is approximately twice the cost of replacing only two traveling screens if only two pumps are replaced.

Reduce Intake Capacity at Petersburg Generating Station: If Unit 2 is converted to closed cycle, the reduced water needs of the plant present additional opportunities to reduce flow and velocity at the CWIS.

Replace Unit 1 circulating water pumps with ones of lower capacity: Unit 1 circ water pumps currently have DIF capacity of 112,000 gpm or 161 MGD which is more than sufficient to provide flow to the other three units' makeup water and other plant needs shown in **Table 4.2-1** in the Technical Memo. Under this scenario and with the existing CWIS, the intake velocity is estimated to be 1.6 fps. Replacing existing Unit 1 pumps with pumps from the Unit 2 bays could lower velocity in proportion to the difference in pump capacity. Unit 2 circ water pumps are rated at 46,250 gpm which is 83% of the existing Unit 1 pumps capacity. Therefore, replacing Unit 1 pumps with Unit 2 pumps, in conjunction with modification of the CWIS described above, would reduce design intake velocity by an additional 17%, reducing CWIS intake design velocity from 0.53 fps to approximately 0.44 fps. Reduced pump capacities could also eventually reduce plant actual intake flow to below the 125 MGD trigger for entrainment requirements.

Replace all CWIS pumps with lower capacity pumps: The existing pumps in all six bays of the existing Units 1 and 2 CWIS could be replaced with pumps of lower capacity to achieve <0.5 fps velocity and still be able to provide sufficient flow to the remainder of the plant. Current water needs of 81 MGD, based on the plant water balance diagram, and 0.5 fps velocity could be achieved with six 17,500 gpm pumps. This modification would require re-piping of the Unit 2 bay pumps to the piping for Unit 1 condensers. It is not clear how this would be accomplished. Further engineering investigation would need to be conducted to determine the feasibility of this option.

Variable Speed Pumps: Installation of variable speed pumps was investigated as a way to reduce intake flow and velocity at the Petersburg Generating Station. Existing circulating water pump controls would be replaced with variable speed pumps and variable speed drives added that could automatically adjust pump speed to draw just the amount of water required for plant needs. This could be also potentially be utilized to reduce the average intake flow over the three-year rolling average timeframe to attempt to drop below the 125 MGD trigger for entrainment requirements. This could also be used to decrease design velocity in combination with modification of the Petersburg Unit 1 CWIS described above by limiting the highest pumping rate to that which would reduce design intake velocity to below 0.5 fps.

Cost Considerations

Modification of CWIS at Petersburg: The facility modifications required to expand Petersburg CWIS to reduce intake velocity to near 0.5 by opening the walls between intake bays, in conjunction with conversion of Unit 2 to full CCC, is estimated to be approximately $300,000 (cost of modification to intake bays only). AECOM investigated the engineering requirements of opening the side walls between bays through review of existing design drawings and developed cost estimates from that study. However, detailed engineering studies would need to be conducted to fully develop this option. The cost to modify the Harding Street Station CWIS to increase screen area for each reduced capacity pump is estimated to be approximately $100,000.

These costs are comparable to the costs of conducting the IM studies required under the rule which are expected to be approximately $250,000. However, there is no guarantee that the results of the impingement study would meet the performance standards for IM survivability and the station may be forced to implement technological solutions anyway. Reduction of velocity to below 0.5 fps eliminates the requirement to meet those standards.

Reduced Intake Capacity at Harding Street: The cost to replace two pumps at Harding Street with 16,000 gpm pumps is estimated to be $1,000,000, based on estimates provided by Harding Street plant personnel.

Reduce Intake Capacity at Petersburg Generating Station:

Replace Unit 1 circulating water pumps with ones of lower capacity: The cost of replacing Unit 1 circulating water pumps with lower capacity pumps from Unit 2 bays at Petersburg Generating Station has been estimated at $0.5MM. This reduction in pump run capacity is expected to result in lower O&M costs due to reduction in electrical use, similar to that expected through use of variable speed pumps described below for an expected O&M cost reduction of $44K per year.

Replace all CWIS pumps with lower capacity pumps: The cost of replacing all six CWIS pumps with lower capacity pumps and modifying the piping from Unit 2 bays to Unit 1 condensers has been estimated to be $3.4MM. This cost assumes replacement of six existing circulating water pumps with six pumps of 17,500 gpm capacity and re-piping Unit 2 circulating water lines to provide flow to the Unit 1 condensers. The cost of detailed engineering study to finalize plans for this modification is included in the total capital cost estimate. The estimated change in O&M costs through installation of lower capacity pumps is negligible from the total O&M costs included in the conversion of Unit 2 to full CCC.

Variable Speed Pumps: Installation of variable speed pumps to replace the two Unit 1 circ pumps at the Petersburg Generating Station is estimated to be $3.0MM, assuming that Unit 2 is converted to full closed cycle cooling. This cost includes installation of two variable speed drives, new pumps, and new motors. Operation and maintenance costs associated with variable speed pumps would actually decrease from existing circ pump O&M costs due to the reduced electrical consumption. The reduction in O&M cost is expected to be $44,000 per year. This cost includes only the reduction in electrical use associated with lower capacity pump motors. Other O&M costs for maintenance of pumps are assumed to be the same as existing.

IM Effectiveness

Velocities of less than 0.5 fps are believed to reduce impingement rates by 90% or greater (Preamble to draft Rule 76 FR 22202). Furthermore, as discussed above, this measure eliminates the need to demonstrate compliance with impingement mortality numeric limitations in the draft rule.

E Effectiveness

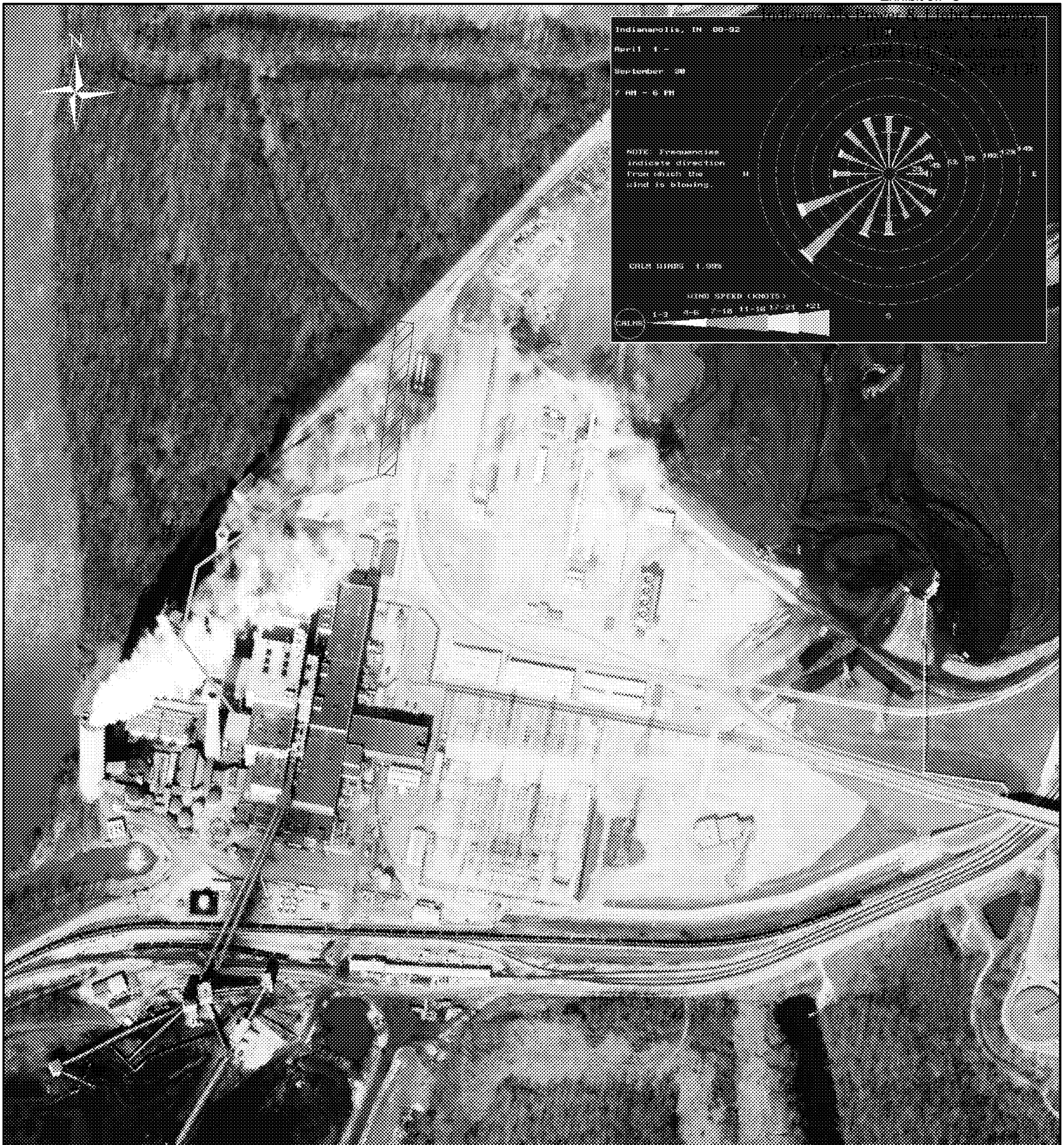
While a reduction in only velocity would not contribute to a reduction in entrainment, the reduction of flow associated with variable speed or lower capacity pumps would provide a proportional reduction in entrainment. Increasing the flow area without a corresponding decrease in flow is not known to be effective at reducing entrainment rates. Therefore, the facility will need to ensure there is a decrease in flow for entrainment BTA purposes.

Conclusions

At Petersburg, there is not sufficient screen space available to get either the actual or design intake velocity below 0.5 fps under the projected operations without expanding the intake structures. If Unit 2 is converted to fully closed cycle, there is some potential that reducing the pumping rate and modifying the intake so that the remaining circulating water pumps draw water through all six intake bays would reduce the value to near 0.5 fps. Replacement of existing Unit 1 circulating pumps with ones of lower capacity or installation of variable speed pumps could reduce velocity further to below 0.5 fps. These options should only be considered if Unit 2 is converted to full closed cycle cooling.

Based on costs, engineering feasibility and input from Petersburg plant personnel, AECOM recommends replacement of existing circulating water pumps in all six bays with pumps of lesser capacity to reduce velocity to below 0.5 fps in the long run. AECOM's recommendations are presented in more detail in **Section 5**.

At Harding Street, with the retirement of Units 3 through 6, velocity reduction would be accomplished through installation of lower capacity pumps and modification of the CWIS.



Legend

Estimated Unit 1 Piping Location

Unit 1 CT Location Used for Pricing Estimate

IPL Petersburg Station Proposed Closed Cycle Cooling Location

AECOM

Figure 2

0 200 400 800 Feet

1 inch = 400 feet

Wind Rose Data Source:
http://www.epa.gov/ttn/naaqs/ozone/areas/wind.htm#dlfi

Date: 11/08/11

Project #: 60220183.05

Figure 3 - Comparison of AECOM Calculations vs. EPRI Guidance

Case 3 - Unit 1 and Unit 2 Expansion

Fossil Plant Retrofit Capital Cost
EPRI - 2011 Technical Report on Closed Cycle Cooling System Retrofit Study

Circulating Water Flow (gpm) 204,500

Degree of Difficulty	Basis (USD per gpm)	Cost (MMUSD)
Easy	181	53.8
Average	275	81.7
Difficult	405	120.3
More Difficult	570	169.3
AECOM's Estimate - Case 3 (1400 ft)	665	136.0

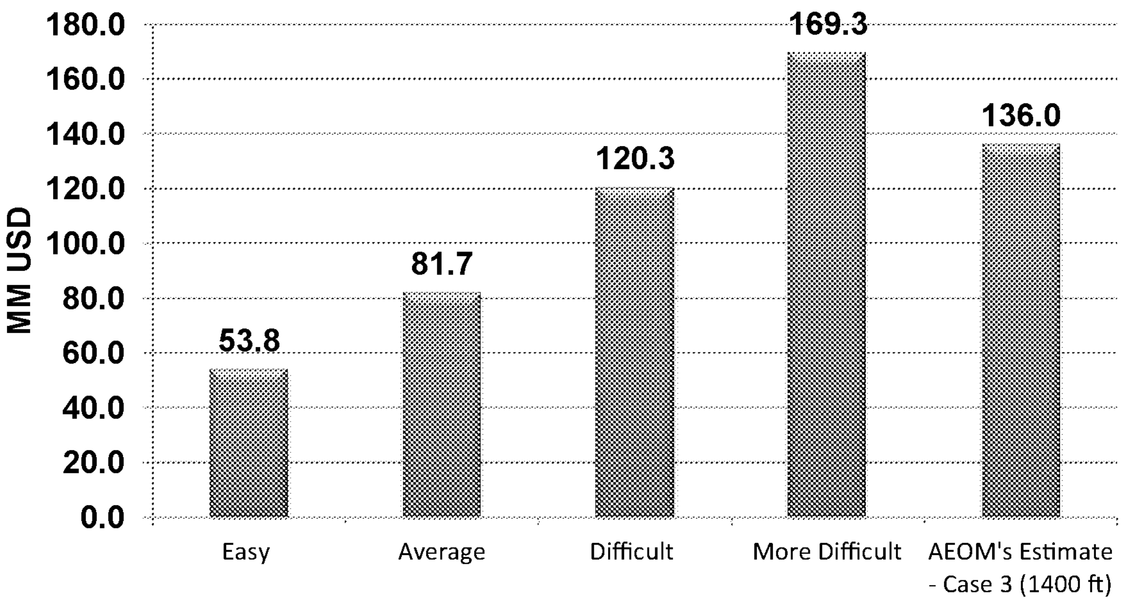


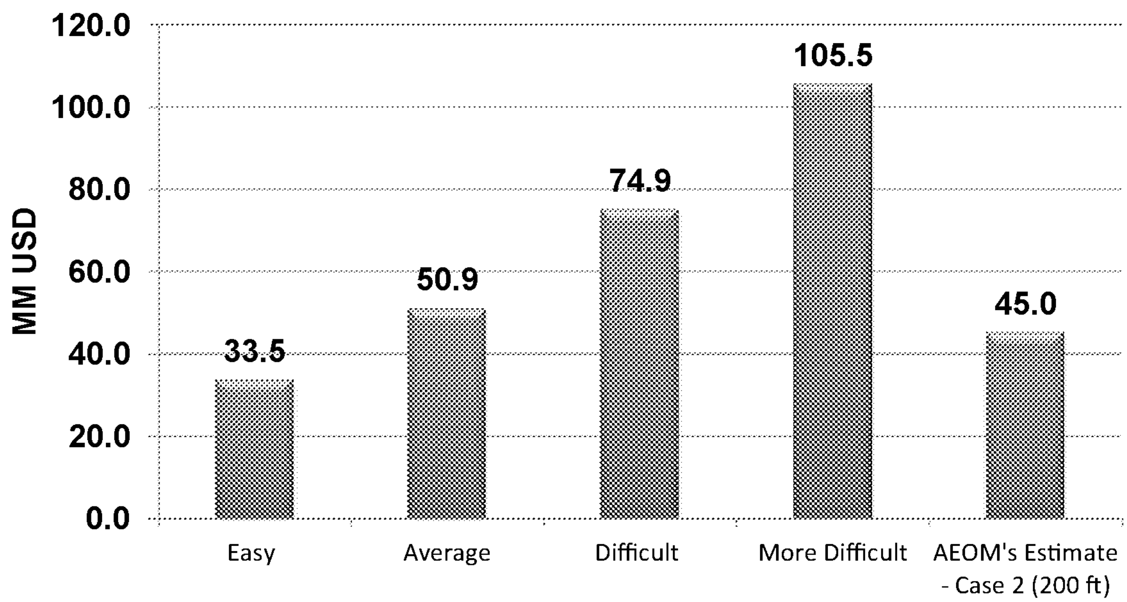
Figure 4 - Comparison of AECOM Calculations vs. EPRI Guidance

Case 2 - Unit 2 Expansion

Fossil Plant Retrofit Capital Cost
EPRI - 2011 Technical Report on Closed Cycle Cooling System Retrofit Study

Circulating Water Flow (gpm) 92,500

Degree of Difficulty	Basis (USD per gpm)	Cost (MMUSD)
Easy	181	33.5
Average	275	50.9
Difficult	405	74.9
More Difficult	570	105.5
AECOM's Estimate - Case 2 (200 ft)	497	46.0



5.0 Application of Technologies at IPL Facilities

The following sequence of potential technical solutions for each station is based on the applicability of the draft rule to existing plant conditions, current and projected station operations, and reviews of available technologies for reducing IM and EM. The options have been defined with the input of IPL staff. While the likely regulatory outcome appears to be straightforward for the Eagle Valley and Harding Street Stations, the likely outcome at Petersburg will depend upon subsequent findings as well as negotiation with IDEM. This uncertainty is a hallmark of the proposed 316(b) rule: no specific technology is specified as BTA. Rather several options are described along with a set of studies to be completed and reviewed by IDEM as part of the technology selection. For these reasons, a set of potential outcomes is presented for Petersburg Generating Station.

In the discussion of options at Petersburg Generating Station and based on discussions with IPL staff, AECOM makes a distinction between a recommended compliance strategy intended to attempt to minimize IPL's cost of compliance and a "planning outcome" intended to support financial planning by IPL. Given the uncertainty in the proposed rule, AECOM believes that this distinction is a very important one. While the recommended strategy may strive to minimize costs, IDEM and EPA have authority to affect the outcome so it is likely to be prudent to anticipate a higher cost scenario in the financial planning process.

5.1 Eagle Valley Station

The requirement to install modified traveling screens applies to all existing facilities for impingement reduction. However, considering the impending retirement of the Eagle Valley Station by the end of 2015, and the 8-year time frame for achieving compliance with IM standards in the rule, AECOM believes that it is unlikely that IDEM would require installation of technology at this facility based on the proposed compliance timeframe and IPL would have a very strong argument against doing so if it were suggested. Importantly, if forced to install expensive technology before closing, the plant would have no opportunity to recover the costs incurred through continued operation. No entrainment compliance actions are anticipated as the facility will be closed soon after the rule becomes effective.

No technical improvements are anticipated or recommended for the Eagle Valley Station. AECOM recommends informing IDEM of the planned closures (Fall 2012) and requesting modification of the NPDES permit to relieve the plant of the permit application requirements included in the rule with a corresponding Agreed Order committing to a closure date for the station (ensure issued by Feb 2013). In this case, no additional reporting will be required.

5.2 Harding Street Station

Impingement

Harding Street Station will continue to operate Unit 7 and will continue to operate one of the existing CWISs to provide water to Unit 7 and other plant needs. Harding Street Station will be required to retrofit the traveling water screens to Ristroph-type screens with a fish return system. In addition, IPL will modify the Unit 5&6 intake so that the intake velocity is less than 0.5 fps.

Under **Case 1** below, IPL could submit the required documents without committing to the closure of Units 3-6. The facility would be required to submit reports 122.21(r)(2), (3), (4), (5), (6), (7), and (8) within six months of finalization of the rule and complete the impingement mortality study over the next 3.5 years (unit closure commitment will need to be confirmed by mid-2016).

Under **Case 2**, IPL would commit to retirement of the four once-through units at the Harding Street Station no later than March 2013. This would leave Unit 7 which operates with closed cycle cooling as the only active unit at the facility. The facility would have to submit reports (2), (3), and (6) as a facility with full closed cycle cooling. However, IDEM may require submittal of all reports 2 through 8, considering that the facility will continue to operate once-through units for a few more years.

In either case, the facility will install modified traveling screens in the remaining active CWIS as required by the draft rule. Unit 7 draws makeup water from the “junction box” which is currently fed from the CWIS from Units 5&6 and Units 3&4. IPL will keep CWIS 5&6 in operation to maintain flow to the junction box to provide makeup water for Unit 7 cooling tower and ash sluice water. Under this scenario, the existing circulating water pumps would be larger than necessary and could be replaced with pumps of lesser capacity and the intake modified to reduce the intake velocity to less than 0.5 fps. Sufficient flow can be provided by one pump at 16,000 gpm. Pumps will be installed in two bays of the existing CWIS with one pump operating and the other in standby. Therefore, modified traveling screens need only be installed in two bays of the existing CWIS.

Harding Street Station IM Requirements:

- **Case 1: Keep option of operating CWIS in current design for potential closure of once-through units by mid-2016**
  - Submit reports 122.21(r)(2), (3), (4), (5), (6), (7), and (8)
  - Plan and complete IM mortality study with flexibility to keep options available for future operating scenarios
  - Commit to future conditions after unit retirement plans become better defined
  - Modify CWIS as shown below
- **Case 2: Commit to closure of four once-though units by March 2013**
  - Notify IDEM of plans to retire units and commit to dates and receive modified NPDES permit with possible need for Agreed Order
  - Submit reports 122.21(r)(2), (3), (4), and (6), if approved by IDEM
  - Modify CWIS as shown below
- **Install Modified Traveling Screens with Fish Handling and Return System (Required in each case)**
  - Replace pumps with ones of lower capacity
  - Complete modification of CWIS to increase screen surface area and further reduce velocity
  - Demonstrate that at future maximum design intake flow, intake velocity is <0.5 fps

Under both of the options described above, the traveling water screens would require retrofit in two bays. The difference between the two cases is the timing of notification of IDEM of the planned closure of the once-through units at Harding Street Station. In both cases, the ultimate goal is to achieve IM compliance either through operation of the MTS FH&RS and reducing the intake velocity to less than 0.5 fps. AECOM recommends the first option which allows the station to delay committing to a closure date until sometime in the future in order to keep options available for future operating scenarios. The schedule for the recommended option for Harding Street Station is presented in the following table.

Compliance Step	Accomplish by Date	Notes
Submit 122.21(r) (2, 3, 4, 5, 6, 7, and 8)	March 2013	Propose to achieve compliance through operation of MTS FH&RS
Monitor for IM	Conduct latent mortality IM monitoring in 2014	Submit results within 3.5 years of rule finalization
Complete detailed engineering study	2014	For MTS FH&RS and CWIS modification
Install modified traveling screens, fish return and handling system in 2 bays (MTS FH&RS)	Install 2018	Achieve IM compliance through operation of MTS FH&RS
Replace 24,500 gpm pumps with two 16,000 gpm pumps	2018	Achieve IM compliance through operation of MTS FH&RS and reduced design intake velocity
Modify CWIS	2018	Achieve IM compliance through operation of MTS FH&RS and reduced design intake velocity
Perform IM monitoring enumeration only	2019 onward	Expected permit condition

The recommended compliance path for Harding Street Station, Case 1 above, is summarized with costs (capital and O&M), schedules, and reporting and monitoring requirements in **Table 6.2**.

Entrainment

Current actual intake flow over the years 2009-2011 for the plant is less than 125 MGD, therefore the Harding Street facility would not be required to submit the entrainment mortality reports under either reporting option described above. However, the director must make a site-specific BTA determination regarding entrainment mortality. Since the future plan is for Unit 7 to operate as closed cycle and all other units would be retired, Harding Street Station would be considered compliant with BTA for entrainment under the proposed rule.

5.3 Petersburg Generating Station

Petersburg Generating Station will continue to operate all four existing units. Currently Unit 1 operates with once-through cooling, Unit 2 operates with once-through cooling except in summer (May-October) when it utilizes a half-capacity closed cycle cooling tower system, and Units 3 and 4 are fully closed cycle. AECOM identified three potential compliance scenarios for Petersburg facility under the proposed rule:

- continued operation under current conditions with the installation of MTS FH&RS;
- conversion of Unit 2 to fully closed cycle while Unit 1 remains once-through; or
- conversion of both Units 1 and 2 to fully closed cycle.

AECOM has assessed the costs and probability that each of these alternatives will be considered compliant by IDEM.

The following paragraphs describe the expected technological path toward compliance under the three future operational cases. These cases are summarized with costs (capital and O&M), schedules, and reporting and monitoring requirements in **Table 6.3**.

Case 1: Continued operation under current cooling conditions

Under this scenario, IPL would install modified traveling screens with fish handling and return system, as required by the draft rule, and demonstrate the level of IM reduction through monitoring. IPL would propose to IDEM that the existing Petersburg facility represents the best technology available for entrainment in its current operating condition by demonstrating that operation of closed cycle cooling towers will increase energy consumption by the plant; increase air emissions (particulates due to cooling tower drift and overall emissions due to decreased plant efficiency); increase water consumption; increase noise levels; increase safety concerns; and increase the potential impacts to plant and therefore grid reliability; that there is little space available on site for locating cooling towers; and that the costs far exceed the benefits in reduction of EM. These arguments would be made through the documents to be submitted five years after finalization of the rule. If IDEM/EPA do not accept these arguments, they may require further operational or technological improvements. The table below presents a potential schedule for the compliance activities under this case. The schedule presented in this table is one potential outcome, however the rule is unclear and provides IDEM significant discretion (particularly related to the monitoring); therefore, the actual schedule could be significantly different.

Case 1 Compliance Schedule:

Compliance Step	Accomplish by Date	Notes
Submit 122.21(r) (2, 3, 4, 5, 6, 7, 8)	March 2013	Propose to achieve compliance through operation of MTS FH&RS; make case for not considering forage species
Submit 122.21(r) (9)	Draft plan in March 2013; Peer reviewed E study plan by September 2013	
Monitor for EM	Complete in 2013-2014	To support benefits assessment
Detailed Engineering Study for MTS FH&RS	2013	
Install MTS FH&RS	2014	Installed to support evaluation of performance required by 122.21(r)(6). Potential that installation not necessary until 2020 when compliance with IM limitations required.
Monitor for IM	2015 – 2019; Submit results of first year of study in mid-2016	Demonstrate achievement of numeric standards
Submit 122.21(r) (10, 11, 12)	September 2017	Advocate that existing system is BTA for EM based on costs relative to benefits and other factors
Monitor for EM	2018-2022	

As noted in the Technical Memorandum, achieving the IM limitations may be challenging or infeasible at Petersburg Generating Station if all species impinged at the facility are considered species of concern by IDEM. However, most of the impinged species that are sensitive are low value forage fish. Therefore, it is possible that IDEM would consider these to not be species of concern. There is support for this position in EPA's preamble to the rule. If these species are not considered when evaluating compliance with the IM limitations, there is a greater potential that the IM limitations would be achievable at this facility. In addition, EPA is actively considering abandoning the impingement mortality limitations in the final rule.

If this is not successful, there is some potential that the IM limitations would lead to the facility having to install closed cycle cooling or taking other measures to get the intake velocity below 0.5 fps and thereby avoiding the requirement to meet the IM limitations.

The proposed Rule's EM requirements are much less proscriptive than the IM requirements. Therefore, IDEM will have substantial discretion when determining what measures are necessary. Under this scenario, AECOM has assumed that IPL will successfully advocate for the existing facility being BTA for EM. We believe this approach has a significant potential to be successful for a number of reasons. There are very few demonstrated, available alternatives for substantially reducing EM other than closed cycle cooling. Alternatives that have relatively low costs are likely to be minimally effective (e.g. variable speed pumps and fine mesh screens).

Closed cycle cooling does have potential to substantially reduce IM. However, in this case the costs of this alternative are much greater than 800 times the monetized benefits. In addition, this technology has significant adverse environmental impacts. Therefore, we believe there is a reasonable chance that IDEM will not require conversion to closed cycle cooling.

The costs presented in **Table 6.3** for this case represent what AECOM feels is the best case scenario for planning purposes and have estimated a 60% probability of outcome.

This case may be made moot if IDEM requires conversion of Unit 2 to closed cycle cooling to reduce thermal impacts to the White River as a condition of the pending or later NPDES permit renewal.

Case 2: Unit 1 remains once-through and Unit 2 is converted to fully closed cycle cooling

There is some potential that IDEM would determine that converting Unit 2 to closed cycle cooling is BTA for reducing EM. With conversion of Unit 2, facility water needs would be reduced sufficiently so that intake velocity could be reduced below 0.5 fps, with installation of lower capacity circulating water pumps. This, in combination with the installation of MTS FH&RS would achieve compliance with the proposed Rule's IM requirements. The reduced intake velocity would avoid the need to demonstrate compliance with numeric limits in the future.

Through-screen intake velocity for Unit 1 CWIS could be reduced to 0.50 fps by replacing the existing circulating water pumps with ones of 17,500 gpm capacity. Further engineering studies would need to be conducted to determine the best method to install the reduced capacity pumps and direct flow to the condensers in Unit 1.

For the purposes of this scenario, we have assumed that the installation of closed cycle cooling and modification of the intake structure and pumps will be completed by 2019. This will ensure that the facility is able to comply with the Rule's IM requirements by demonstrating that their intake velocity is less than 0.5 fps by the Rule's deadline for compliance with IM (2020). However, other schedules for installing closed cycle cooling are possible.

Case 2 Compliance Schedule:

Compliance Step	Accomplish by Date	Notes
Submit 122.21(r) (2, 3, 4, 5, 6, 7, 8)	March 2013	Propose to achieve compliance through operation of MTS FH&RS; make case for not considering forage species
Submit 122.21(r) (9)	Draft plan in March 2013; Peer reviewed E study plan by September 2013	
Monitor for EM	Complete in 2013-2014	To support benefits assessment
Detailed Engineering Study for MTS FH&RS	2013	
Install MTS FH&RS	2014	
Monitor for IM	2015 – 2019; Submit results of first year of study in 2016	Demonstrate achievement of numeric standards
Submit 122.21(r) (10, 11, 12)	September 2017	Propose that existing system is BTA for EM – IDEM does not agree
Engineering for CCC conversion	2018	
Convert Unit 2 to CCC	2019	Reduces flow and velocity
Modify CWIS/reduce pump capacity	2019	Reduces velocity to <0.5 fps for IM BTA
Monitor for EM	2020-2022	Expected NPDES permit condition

The reduced flow associated with converting Unit 2 to fully closed cycle will result in significant reductions in EM. The replacement of existing Unit 1 circulating water pumps with reduced capacity pumps or installation of variable speed pumps would further reduce EM. Therefore, this case would be likely to be acceptable to IDEM if they reject Case 1.

The costs presented in **Table 6.3** for this case represent the mid-level estimated cost impact of the 316(b) rule on the Petersburg facility. AECOM estimates a 25% likelihood of this outcome and recommends that this cost be used for general planning purposes at this time.

Case 3: Convert Units 1 and 2 to fully closed cycle cooling.

There is some potential that IDEM would determine that BTA for EM is the conversion of both Units 1 and 2 to closed cycle cooling. While AECOM does not believe this is the most likely outcome, this alternative was considered for potential planning purposes. Under this scenario, cooling tower makeup for all four units would be provided through the Unit 1 and 2 CWIS at reduced flow. Units 1, 2, 3 and 4 will draw cooling tower makeup water from the discharge canal from the existing CWIS associated with Units 1 and 2.

Based on the facility water balance diagram, it is estimated that approximately 56,000 gpm (81 MGD), which includes estimates of makeup water for Units 1 and 2 cooling towers, would be needed to operate Petersburg Generating Station with four units on closed cycle cooling (See **Table 4.2-1** in the Technical Memo). Replacing the existing circulation pumps with lower capacity pumps would bring through screen velocity below 0.5 fps. Further engineering studies associated with this option in combination with operational needs would need to be conducted to determine the actual required pump capacities. The cost of replacing the pumps is included in the estimated cost for this scenario. Alternatively, the final 316(b) rule may consider that generating units using closed cycle cooling are BTA regardless of the specifics of the cooling water intake structure.

Case 3 Compliance Schedule:

Compliance Step	Accomplish by Date	Notes
Submit 122.21(r) (2, 3, 4, 5, 6, 7, 8)	March 2013	Propose to achieve compliance through operation of MTS FH&RS; make case for not considering forage species
Submit 122.21(r) (9)	Draft plan in March 2013; Peer reviewed E study plan by September 2013	
Monitor for EM	Complete in 2013-2014	To support benefits assessment
Detailed Engineering Study for MTS FH&RS	2013	
Install MTS FH&RS	2014	
Monitor for IM	2015 – 2019; Submit results of first year of study in 2016	Demonstrate achievement of numeric standards
Submit 122.21(r) (10, 11, 12)	September 2017	Propose existing system is BTA for EM – IDEM does not agree
Engineering for CCC Conversion	2018	
Convert Units 1 AND 2 to CCC	2019	CCC is determined to be BTA for EM for both units

The costs presented in **Table 6.3** for this case represent the worst case scenario for Petersburg Generating Station and are considered less than 15% probability.

6.0 Recommendations for Compliance Strategy

6.1 Basis for Compliance Strategy Recommendations

AECOM believes that it will be in IPL's interest to carefully plan for the implementation of Section 316(b) including both anticipating changes in the rule from the proposal and advocating for the most cost-effective approaches to compliance. Such an approach should include careful evaluation of available compliance approaches including planning for the potential that closed cycle cooling may be required. AECOM makes a distinction between a recommended compliance strategy intended to attempt to minimize IPL's cost of compliance and a "planning outcome" intended to support financial planning by IPL. Given the uncertainty in the proposed rule, AECOM believes that this distinction is an important one. While the recommended strategy may strive to minimize costs, IDEM and EPA have authority to affect the outcome so it is likely to be prudent to anticipate a higher cost scenario in the financial planning process.

The rule as proposed does not include any sort of explicit assumption that closed cycle cooling will be necessary at a given plant. In fact, in several places in the proposal, EPA makes the point that closed cycle cooling is not generally available at plants across the country and that retrofitting to closed cycle cooling will have adverse impacts that should be weighed on a site-specific basis against the environmental benefits. Operation of closed cycle cooling towers will increase energy consumption by the plant; reduce the thermal impact on the receiving stream; increase in air emissions (particulates due to cooling tower drift and overall emissions due to decreased plant output); increase water consumption; increase noise levels; increase safety concerns; and increase the potential impacts to plant and therefore grid reliability (see the table below in **Section 6.2**). All of these factors must be evaluated and, based on information presented by IPL, will be considered by IDEM and EPA when determining BTA for EM. EPA also calculates a highly adverse cost to benefit ratio for the installation of closed cycle cooling on a nationwide basis. At the Petersburg Station, the cost-to-benefit ratio is much higher (greatly exceeding 800:1). This provides a strong basis for advocating the closed cycle cooling is not BTA for EM at this facility. Finally, while the proposed rule appears to make achievement of impingement mortality controls both costly and uncertain, AECOM believes that the final rule is likely to provide a more reasonable approach to impingement mortality controls potentially including no quantitative performance goals for Ristroph-modifications of traveling screens. These changes are likely to provide facilities a clear path towards compliance with IM requirements.

For all of these reasons, AECOM recommends that IPL take careful stock of compliance measures beyond closed cycle cooling. In particular, the conclusions of this report should be carefully re-evaluated once the final rule is released. This re-evaluation should include careful and prompt study of the final rule to address the following questions:

- What are the allowed compliance approaches?
- What would each approach require of IPL?
- What uncertainties exist relative to definitions, agency response, etc.?
- How should those uncertainties be addressed? Is it possible to propose a strategy to reduce uncertainty that is reasonable, protective, and provides IPL with a cost-effective outcome?
- What is the schedule for implementation and how quickly must retrofits occur?
- What are the relative merits of each approach for IPL?

6.2 Recommended Facility Compliance Strategies

The attached tables present compliance options, schedules and approximate costs for each of the IPL stations. These options are presented as the recommended strategy for Eagle Valley and Harding Street Stations, and the best case, middle case, and worst case scenario for Petersburg Generating Station, considering cost, regulatory compliance implications and impact on plant operations. The compliance schedules and costs are summarized in **Tables 6.1, 6.2**, and **6.3** for Eagle Valley, Harding Street and Petersburg Stations, respectively. These scenarios are fully described in **Section 5** and are presented to help IPL estimate the impacts of the draft rule, as written, on the future operations of the fleet. AECOM's recommended option and predicted probability of each option is presented for each plant. It must be noted that these conclusions are based on the draft rule as written and that it is expected that the final rule will have changed significantly when it is published in final form in July 2012.

Costs presented include those for completion of required reports and studies described in **Section 3** and capital and O&M costs for the technologies described in **Section 4**. The costs expected to be incurred over the next 10 years under each compliance option for each station are totaled.

Eagle Valley Station: AECOM understands that IPL plans to inform IDEM of the planned closures and request modification of the NPDES permit to relieve the plant of the permit application requirements included in the rule with a corresponding Agreed Order committing to a closure date for the station (as described in **Section 3.2**).

Harding Street Station: AECOM recommends that the plant submit reports 122.21(r)(2), (3), (4), (5), (6), (7), and (8) within six months of finalization of the rule and proceed with the impingement mortality study, but not commit to any other technologies until unit closure plans are defined and relayed to IDEM (**Table 6.2**). While the proposed rule would require that any traveling screens reflect post-Ristroph modifications, IPL should strive to delay retrofits to any cooling water intake structures that will be retired. This should be feasible given the implementation schedule outlined in the proposed rule. For the purposes of planning, the costs shown in **Table 6.2** are for installation of modified traveling screens on two bays of CWIS 5&6 and the expansion of the intake to achieve velocities of less than 0.5 fps. With these changes, the facility would be compliant with the Rule's IM requirements. Potential costs for retrofit of the screens at Units 3 and 4 are not considered. Installation of MTS FH&RS and modification of CWIS and installation of lower capacity pumps to achieve through-screen velocity less than 0.5 fps would be considered BTA for IM.

Petersburg Generating Station: There are a number of potential outcomes for Petersburg Generating Station under the draft rule. To increase the chances that a low cost alternative is accepted by IDEM, AECOM recommends the following strategy for complying with the IM and EM requirements of the rule.

To minimize the potential that IDEM concludes that closed-cycle cooling is BTA for EM, AECOM recommends that the entrainment mortality submittals emphasize the very high costs relative to the benefits and other adverse environmental impacts associated with closed cycle cooling. The cost to benefit ratio of closed cycle cooling exceeds 800:1. This very high cost to benefit ratio should be emphasized in the submittals to IDEM. In addition, the other adverse environmental impacts associated with closed cycle cooling should be clearly documented and emphasized. Operation of closed cycle cooling towers will increase energy consumption by the plant; reduce the thermal impact on the receiving stream; increase air emissions (particulates due to cooling tower drift and overall emissions due to decreased plant efficiency); increase water consumption; increase noise levels;

increase safety concerns; and increase the potential impacts to plant and therefore grid reliability. The following table presents a preliminary assessment of the expected impacts of these environmental factors for each of the compliance strategy cases examined for the Petersburg Generating Station. All of these factors must be evaluated and will be considered by IDEM and EPA when determining BTA for EM.

Preliminary Assessment of Non-water Quality and Other Environmental Impacts per Requirements of 122.21(r)(12)(i-ix) for Potential Compliance Options at Petersburg Station

40 CFR 122.21(r)(12)	Factor	Case 1: Status Quo is BTA for Entrainment	Case 2: CCC for Unit 2 is BTA for Entrainment	Case 3: CCC for Units 1&2 is BTA for Entrainment
(i)	Change in energy consumption	None	Increase of ~0.5% for parasitic load and ~0.5% for loss of efficiency	Increase of ~1% for parasitic load and ~1% for loss of efficiency
(ii)	Change in thermal discharge	None	Decline - ~43%	Decline - >90%
(iii)	Change in air emissions	None	Increase due to replacement power and cooling tower emissions	Increase due to replacement power and cooling tower emissions
(iv)	Change in noise levels	None	Significant associated with 8 cooling tower cells	Significant associated with 16 CT cells
(v)	Impacts to safety	None	Increased fogging and icing potential with 8 additional cooling tower cells	Increased fogging and icing potential with 16 additional cooling tower cells
(vi)	Impacts to grid reliability	None	Loss of generating capacity during construction as well as loss of plant capacity	Loss of generating capacity during construction as well as loss of plant capacity
(vii)	Impacts to facility reliability	None	Cooling tower maintenance is costly but no significant impacts to reliability	Cooling tower maintenance is costly but no significant impacts to reliability
(viii)	Changes in water consumption	None	Consumptive use of water will increase due to evaporative losses of approximately 1.5 MGD	Consumptive use of water will increase due to evaporative losses of approximately 3 MGD
(ix)	Potential mitigation measures	None	Mitigation measures of plume abatement and optimization of construction timing are assumed	Mitigation measures of plume abatement and optimization of construction timing are assumed

In combination, the submittals related to entrainment (i.e. those required by 122.21(r) (10, 11, 12)) should support the conclusion that the existing cooling configuration of the facility is BTA and conversion to closed cycle cooling is unwarranted. AECOM believes this strategy has a reasonable potential for success. Historically, IDEM and other regulatory agencies have rarely concluded that retrofit to closed cycle cooling is necessary to reduce EM or IM. We understand that IDEM and EPA are concerned about thermal discharges from the Petersburg facility. This factor may also lead to requirements to install closed cycle cooling. However, predicting the likely impact of thermal considerations is beyond the scope of this study and difficult to anticipate without consultation with the agencies. Therefore, it may be prudent for IPL to plan for the financial consequences of a more adverse outcome.

To comply with the Proposed Rule's IM requirements, modified traveling screens with fish handling and return system would be required to be installed. Given the configuration of the intake and circulating water pumps, the existing intake velocity exceeds 0.5 fps. Therefore, the IM numeric limitations will apply. Complying with these IM limitations will be a challenge if they are applied to the full suite of organisms impinged at the facility. To address this issue, AECOM recommends that IPL advocate that gizzard shad and other sensitive forage species are not species of concern as defined in the proposed rule and therefore the IM limitations should not apply to them. If IDEM accepts this position, there is a greater potential that the facility could achieve the rule's IM limitations.

If the IM limitations are not achieved at the Petersburg facility, additional modifications may be required. These could include expanding the intake to achieve <0.5 fps intake velocity. The implications of this expansion would be dependent on the cooling configuration that was determined to be BTA for EM. If once-through cooling is maintained, achieving intake velocity < 0.5 fps would likely be very expensive and potentially infeasible. In this case, there would be relatively limited options under the proposed rule. Conceivably this could lead to the requirement to install closed-cycle cooling to reduce the intake velocity. However, discussions with EPA have indicated that it was not their intention to require closed-cycle cooling to reduce IM. As a result, we believe the final rule may include provisions to limit the potential of this outcome including dispensing with the impingement mortality performance standard.

In summary, AECOM's recommended strategy for Petersburg Generating Station is to propose that retrofit to the required modified traveling screen system achieves BTA for IM; advocate for exclusion of sensitive forage species from consideration in IM survivability rates; and propose existing conditions as BTA for EM. AECOM recommends installation of modified traveling screen system within the first few years of coverage by the rule to allow sufficient time to proceed with other more costly options if forced to by the agencies.

While this is AECOM's recommended strategy, we acknowledge that IDEM and EPA have expressed concern about thermal impacts. For this reason, IPL should consider a financial plan that accommodates installation of closed cycle cooling at the plant which could be driven by either tighter thermal limits or by the decision of IDEM's NPDES Director based on 316(b) requirements.

Based on this review, AECOM recommends that IPL re-visit the compliance strategy outlined in this document after finalization of the rule. This should include the broad goals (e.g., optimal outcome of the process) as well as important steps within the process (e.g., addressing critical questions with IDEM; goals, methods, and timing of monitoring studies).

AECOM believes that outreach to IDEM following the release of the final rule will be very important. Such outreach might be used to: (1) highlight and resolve critical resource constraints such as the availability of peer reviewers; (2) resolve confusion regarding the implementation schedule and study goals; (3) introduce IPL's proposed compliance approach and advocate for its merits; and (4) discuss the basis for gizzard shad and other sensitive forage species be considered not species of concern.

IPL may consider discussing with IDEM the potential to better integrate the considerations of controls aimed at impingement with those intended to mitigate entrainment.

Table 6.1 Eagle Valley Station Compliance Plan
Indianapolis Power & Light
Section 316(b) Milestones, Potential Outcomes, and Estimated Costs

Plant	**Eagle Valley Station**	
Units	**Units 1 through 6 once-through cooling**	

Critical Milestones

Notify IDEM of Unit Closures (Case 1). No further action required	September 2012	Sign Agreed Order before March 2013 due date for submittals
Decommission Units 1-6	by end of 2015	
Begin Monitoring for IM	N/A	
Retrofit for IM Controls	N/A	
Submit 122.21(r)9,10,11,12	N/A	
Begin Monitoring for EM	N/A	
Retrofit for EM Controls	N/A	

Important Site-Specific Considerations

All Eagle Valley Station units have been designated for decommissioning by end of 2015. No further technology assessment will be conducted for this facility. IDEM will be notified of the plant closure and a recommendation will be made that no further 316(b) compliance actions will be conducted at this facility no later than September 1, 2012. However, IDEM may require some additional reporting or studies as part of on-going NPDES permit compliance until the end of 2015.

Eagle Valley Station Case 1 - 80% Probability

Summary	**Regulatory Findings:**	Plant to be shut down. Commit closure dates to IDEM though Agreed Order after permit is modified. No permit application requirements apply based on Agreed Order.
	Scope of Plant Modification(s):	None
Monitoring Scope	None	

Estimated Costs

	Capital	O&M/yr	Energy Penalty/yr	Engineering	PAR	Monitoring/yr	10-Year Cost
No further action required					$0		$0
Total Scenario Cost	$0	$0	$0	$0	$0	$0	$0

Estimated Downtime	N/A
Benefits	.

Eagle Valley Station Case 2 - 20 % Probability

Summary	**Regulatory Findings:**	Plant to be shut down. Commit closure dates to IDEM. Permit modified to require submittal of PAR documents, but no monitoring or technologies required.
	Scope of Plant Modification(s):	None
Monitoring Scope	None	

Estimated Costs

	Capital	O&M/yr	Energy Penalty/yr	Engineering	PAR	Monitoring/yr	10-Year Cost
Submit 122.21(r)2,3,5,6,7,8					$20,000		$20,000
Total Scenario Cost	$0	$0	$0	$0	$20,000	$0	$20,000

Estimated Downtime	N/A
Benefits	Allows full permit compliance until shut down. Can inform IDEM of shutdown through submittal of PAR documents. Most information required in the documents is already in hand from previous submittals.

Table 6.2 Harding Street Station Compliance Plan
Indianapolis Power & Light
Section 316(b) Milestones, Potential Outcomes, and Estimated Costs

Plant	**Harding Street Station**
Units	**Units 3, 4, 5, and 6 once-through cooling; Unit 7 closed cycle cooling**

Critical Milestones

Submit 122.21(r)2,3,5,6,7,8 (as applicable)	March 2013	
Begin Monitoring for IM	March 2014	Dependent on compliance path chosen
Submit IM Reduction Plan	March 1, 2016	Submit unit closure information
Retrofit for IM Controls	2018	Must achieve compliance by 2020
Submit 122.21(r)9,10,11,12	N/A	
Begin Monitoring for EM	N/A	
Retrofit for EM Controls	N/A	

Important Site-Specific Considerations

IPL has recently designated Units 3, 4, 5 and 6 for decommissioning by the end of 2015. Unit 7 will continue to operate with closed cycle cooling. Cooling water would be supplied through the CWIS for Units 5 and 6 modified to reduce intake velocity to <0.5 fps.
Unit 7 is CCC and draws water from the junction box which is fed from Units 3-6 condenser water and other sources. Unit 7 intake does not meet the definition of CWIS because it withdraws from the junction box which is not a water of the US. Therefore, as currently employed, it is exempt from proposed rule.
For these reasons, the potential measures discussed below would be applicable to the CWIS for Units 5 and 6. This CWIS will continue to operate after the closure of Units 3, 4, 5, and 6.
Gizzard shad 40.8% of impinged fish. CWISs are on river side built up above flood plain. Space available on either side for expansion. Hot water return and Seasonal CTs for 5&6 run underground on either side of CWIS. Intake bays for old Units 1 and 2 are not used, but still in place.
River is shallow, heavy sediment loading (occasional dredging is routine), and heavy debris loading. Sand bar and peninsula have formed out of sediment deposition and create an embayment in front of CWISs. Significant fluctuations in flood levels have been observed.

Harding Street Case 1 - 80% Probability

Summary	**Regulatory Findings:**	Complete 122.21 submittals; delay notification of unit closures until after submittal of documents in March 2013; propose retrofit of screens and intake modification to achieve <0.5 fps intake velocity as BTA for IM; Commitment to unit closure date required by mid-2016; AIF is < 125 MGD therefore, no national requirements for EM
	Scope of Plant Modification(s):	Ristroph retrofit with fish return and continuous screen rotation on two bays of CWIS 5 and 6. Modify CWIS and reduce pump capacity to reduce velocity to below 0.5 fps.
Monitoring Scope		IM: Monitoring would consist of biweekly enumeration monitoring only. Assumed monitoring will continue annually for 3-years of current permit period; however alternative requirements are possible. No EM monitoring.

Estimated Costs (USD 2012)

	Year	Capital	O&M/yr	Energy Penalty/yr	Engineering	PAR	Monitoring/yr	Cost (USD Variable)	NPV (Cost)
Submit 122.21(r)(2,3,4,5,6,7,8)	2013					$55,000		$55,000	$55,000
Detailed Engineering Study	2014				$60,000			$62,302	$58,725
Install MTS, FR&HS in 2 bays	2018	$1,600,000	$52,000		$200,000			$2,259,338	$1,877,567
Modify CWIS	2018	$100,000						$111,955	$93,761
Replace circ pumps	2018	$1,000,000						$1,119,554	$937,609
Monitor for IM (Latent Mortality)	2014						$250,000	$259,590	$244,689
Monitor for IM (Enumeration)	2019-2022						$100,000	$469,501	$365,137
								Total	
Total Scenario Cost								$4,337,241	$3,632,488
	Note: $200,000 under Engineering is for MTS pilot study if required.								
Estimated Downtime	Assume 2 months for installation. Water would be provided through other bays during installation, so no Unit 7 downtime is anticipated.								
Benefits	Maintain options for future operating conditions until plans are solidified.								

Harding Street Case 2 - 20% Probability

Summary	**Regulatory Findings:**	Notify IDEM of unit closures in September 2012 prior to submittal of documents in March 2013; commit to closure by the end of 2015; Obtain Agreed Order from IDEM that relieves plant of the need to conduct monitoring due to plans to be fully CCC by 2015; propose retrofit of screens and intake modification to achieve <0.5 fps intake velocity as BTA for IM; AIF is < 125 MGD therefore, no national requirements for EM
	Scope of Plant Modification(s):	Ristroph retrofit with fish return and continuous screen rotation on two bays of CWIS 5 and 6. Modify CWIS and reduce pump capacity to reduce velocity to below 0.5 fps.
Monitoring Scope		IM: Agreed Order with IDEM commits to closure, relieves plant of need to perform monitoring before retrofit. Enumeration-only monitoring after retrofit. Monitoring would consist of biweekly enumeration monitoring only. Assumed monitoring will continue annually for 3-years of current permit period; however alternative requirements are possible. No EM monitoring.

Estimated Costs (USD 2012)

	Year	Capital	O&M/yr	Energy Penalty/yr	Engineering	PAR	Monitoring/yr	Cost (USD Variable)	NPV (Cost)
Notify IDEM of unit closures, Agreed Order	2012								
Submit 122.21(r)(2,3,4,6)	2013					$40,000		$40,000	$40,000
Detailed Engineering Study	2014				$60,000			$62,302	$58,725
Install MTS, FR&HS in 2 bays	2018	$1,600,000	$52,000		$200,000			$2,259,338	$1,877,567
Modify CWIS	2018	$100,000						$111,955	$93,761
Replace circ pumps	2018	$1,000,000						$1,119,554	$937,609
Monitor for IM (Enumeration)	2019-2022						$100,000	$469,501	$365,137
								Total	
Total Scenario Cost								$4,062,651	$3,372,799
	Note: $200,000 under Engineering is for MTS pilot study if required.								
Estimated Downtime	Assume 2 months for installation. Water would be provided through other bays during installation, so no Unit 7 downtime is anticipated.								
Benefits	Relieves plant of some permitting requirements and the need to conduct IM monitoring prior to retrofit of CWIS								

Table 6.3 Petersburg Station Compliance Plan
Indianapolis Power & Light
Section 316(b) Milestones, Potential Outcomes, and Estimated Costs

Plant	**Petersburg Station**	
Units	**Units 1 and 2 once-through cooling; Units 3 and 4 closed cycle cooling**	

Critical Milestones

Submit 122.21(r)(2,3,5,6,7,8,9)	March 2013	
Begin Monitoring for IM	March 2015	After installation of MTS FH&RS; submit results by March 2106
Retrofit for IM Controls	2014	Must achieve compliance by 2020 but maybe sooner
Submit 122.21(r)(10,11,12)	September 2017	
Begin Monitoring for EM	2013	Monitoring under 122.21(r)9); Submit results by September 2017; Second effort anticipated after BTA decision.
Retrofit for EM Controls	TBD	No set compliance timeframe; TBD by IDEM

Important Site-Specific Considerations

Unit 2 has existing cooling tower for half the thermal load including infrastructure for portions of the second half.
Half CT for Unit 2 has room to expand to the north. Piping to Unit 2 CT may be sufficient to increase to full CCC.
Units 1 or 2 circ pumps must continue to provide make up water for Units 3&4.
Gizzard shad 68% of impinged fish. IM historically maximum in January and February, with second smaller peak in September. EM nearly all occurs in May, June and July.
Shallow river, heavy sediment loading, heavy debris loading. Wide variations in water levels have been observed. Low head dam downstream of CWIS maintains constant water level during low flow conditions.
Annual economic value of the fish entrained or impinged at Petersburg was estimated to be $3,274. Over 60% of this was attributed to entrainment. Installation of cooling towers at Petersburg was estimated to yield an annual economic benefit of $3,045 through reductions in E and I. (EPRI report to IPL, 2011)

Best Case Scenario: Estimated Probability of Outcome 60%

Estimated probability based on IDEM and national precedent; adverse cost to benefit ratio for CCC; other adverse environmental impacts of CCC; and lack of requirement for CCC in the proposed rule.
Ristroph retrofit and fish return are required by the proposed rule. Effort is scheduled to allow transition to other cases, if necessary.

Summary	**Regulatory Findings:**	Propose that retrofit of screens is BTA for IM. Advocate for removal of gizzard and threadfin shad and other forage species from consideration in IM survivability rates. Other hardier species survivability approaches 85%. Propose existing conditions as BTA for EM. Measurement of IM and EM as well as IM retrofit are done relatively early. There is a potential that IM performance goals will not be achieved, making Case 2 a potential outcome.
	Scope of Plant Modification(s):	Ristroph retrofit with fish return. Continuous screen rotation. Potential for transition to other compliance strategies.
Monitoring Scope		IM: Monitoring would occur biweekly; annually 12 monitoring events would consistent of latent mortality monitoring; the remaining 14 monitoring events would consist of enumeration only. Identify naturally moribund individuals and species of concern. Evaluate mortality. Monitor for the five year permit period, starting the year after installation of MTS FH&RS. First report of results is due March 2016. EM: Monitoring to occur in 2013 under 122.21(r)(9) to support benefits assessment. Additional monitoring as part of NPDES permit requirements after BTA decision (2018 to 2022).

Estimated Costs (USD 2012)

Phase	Year	Capital	O&M/yr	Energy Penalty/yr	Engineering	PAR	Monitoring/yr	Cost (USD variable)	NPV (Cost)
Submit 122.21(r)(2,3,5,6,7,8)	2013					$55,000		$55,000	$55,000
Submit 122.21(r)(9)	2013					$25,000	$150,000	$177,850	$173,398
Detailed Engineering Study	2013				$100,000			$101,900	$98,932
Install MTS, FH&RS	2014	$3,400,000	$190,000		$200,000			$5,457,510	$4,941,482
Monitor for IM	2015-2019						$250,000	$1,399,939	$1,172,146
Submit 122.21(r)(10,11,12)	2017					$150,000		$164,802	$142,160
Monitor for EM	2018-2022						$150,000	$872,185	$688,346
								Total	
Total Scenario Cost								$8,229,185	$7,271,464

Note: $200,000 under Engineering is for MTS pilot study if required.

Estimated Downtime	MTS FH&RS: Unit 1 will require downtime during Fall 2014 outage and Unit 2 in Spring 2014. Design is expected to take six months prior to construction which is expected to take 2 months.
Benefits	Least cost option, however no guarantee that IM goals will be met or that IDEM will accept no CCC. Cost to benefit ratio for installation of cooling towers is orders of magnitude greater than EPA estimates of 21:1. Annual benefits of installation of cooling towers is estimated to be $3,045 while cost of O&M alone for Unit 2 conversion is over $2,700,000 per year (Case 2, below). This represents a cost to benefit ratio of greater than 800:1 before capital costs are considered. Note that estimated monetized benefits do not include non-use benefits.

Middle Case Scenario: Estimated Probability of Outcome - 25%

Estimated probability based on factors mentioned under Best Case with recognition that IM BTA was not met under Case 1 and IDEM may require some costly action that is seen as more effective for IM & EM.
Retrofit of Unit 2 to CCC would be lower cost/flow rate and therefore more cost-effective than retrofit of both units (worst case, see below)
IDEM accepts lower cost option as result of negotiation.

Summary	**Regulatory Findings:**	Retrofit of screens and reduction of velocity to <0.5 fps is BTA for IM; EM BTA for Unit 2 is CCC and for Unit 1 is reduced flow.
	Scope of Plant Modification(s):	Ristroph retrofit with fish return and continuous screen rotation. Fully convert Unit 2 to closed cycle cooling. Modify CWIS: install six reduced capacity pumps and re-pipe U2 pumps to U1 condenser.
Monitoring Scope		IM: Monitoring would occur biweekly; annually 12 monitoring events would consistent of latent mortality monitoring; the remaining 14 monitoring events would consist of enumeration only. Identity naturally moribund individuals and species of concern. Evaluate mortality. Monitor for the five year permit period, starting the year after installation of MTS FH&RS. First report of results is due March 2016. EM: Monitoring to occur in 2013 under 122.21(r)(9) to support benefits assessment. Additional monitoring as part of NPDES permit requirements after BTA decision (2020 to 2022).

Estimated Costs (USD 2012)

Phase	Year	Capital	O&M/yr	Energy Penalty/yr	Engineering	PAR	Monitoring/yr	Cost (USD variable)	NPV (Cost)
Submit 122.21(r)(2,3,5,6,7,8)	2013					$55,000		$55,000	$55,000
Submit 122.21(r)(9)	2013					$25,000	$150,000	$177,850	$173,398
Detailed Engineering Study	2013				$100,000			$101,900	$98,932
Install MTS, FH&RS	2014	$3,400,000	$190,000		$200,000			$5,457,510	$4,941,482
Monitor for IM	2015-2019						$250,000	$1,399,939	$1,172,146
Submit 122.21(r)(10,11,12)	2017					$150,000		$164,802	$142,160
Detailed Eng for CCC Conversion[1]	2018	$1,700,000						$1,903,242	$1,593,935
Convert Unit 2 to CCC[1]	2019	$43,300,000	$2,300,000	$400,000				$58,994,055	$47,519,074
Estimated cost of outage loss	2019	$6,300,000						$7,187,202	$5,843,853
Modify CWIS/reduce pump capacity[2]	2019	$3,400,000						$3,878,807	$3,153,825
Monitor for EM	2020-2022						$150,000	$533,128	$408,566
								Total	
Total Scenario Cost								$79,853,435	$65,102,371

Note: Energy penalty is considered an O&M cost, but is listed separately for illustration.
[1] Detailed engineering costs are considered a Capital of closed cycle cooling system. Unit 2 conversion must be completed by September 2020 to meet IM 8-year due date
[2] Capital cost includes $100,000 engineering study. Net increase/decrease in O&M cost with reduced pump capacities is negligible.

Estimated Downtime	MTS FH&RS: Unit 1 will require downtime during Fall 2014 outage and Unit 2 in Spring 2014. Design is expected to take six months prior to construction which is expected to take 2 months. Construction of Unit 2 cooling tower system is expected to take 11 months. Downtime is estimated to be approximately one month and occur during planned outage in spring 2019. Engineering will be completed in the preceding year, 2018. Other modifications listed should be able to be completed with minimal downtime or during the Unit 2 conversion.
Benefits	Converting Unit 2 to CCC allows for other options (VSPs, modification of CWIS, replacement with lower capacity pumps) to reduce CWIS velocity to below 0.5 fps. CT infrastructure for Unit 2 is in place, reducing cost associated with new towers. Shows good faith effort to reduce flows and thereby, EM.

Worst Case Scenario: Estimated Probability of Outcome - 15%

Estimated probability based on factors outlined above.

Summary	**Regulatory Findings:**	Retrofit of screens is BTA for IM. CCC is determined to be BTA for EM for both units.
	Scope of Plant Modification(s):	Ristroph retrofit with fish return and continuous screen rotation. Evaporative cooling towers are installed for both units.
Monitoring Scope		Though the facility will be fully closed cycle in the future, monitoring requirements will be the same as the first two cases until retrofit to CCC at which time, monitoring requirements will be lessened. IM: Monitoring would occur biweekly; annually 12 monitoring events would consistent of latent mortality monitoring; the remaining 14 monitoring events would consist of enumeration only. Identity naturally moribund individuals and species of concern. Enumerate impingement only for the five year permit period, starting the year after installation of MTS FH&RS. First report of results is due in March 2016. EM: Monitoring required under 122.21(r)(9) to define monetized benefits. No monitoring of EM required under NPDES permit post-retrofit to closed cycle.

Estimated Costs (USD 2012)

Phase	Year	Capital	O&M/yr	Energy Penalty/yr	Engineering	PAR	Monitoring/yr	Cost (USD variable)	NPV (Cost)
Submit 122.21(r)(2,3,5,6,7,8)	2013					$55,000		$55,000	$55,000
Submit 122.21(r)(9)	2013					$25,000	$150,000	$177,850	$173,398
Detailed Engineering Study	2013				$100,000			$101,900	$98,932
Install MTS, FH&RS	2014	$3,400,000	$190,000		$200,000			$5,457,510	$4,941,482
Monitor for IM	2015-2019						$250,000	$1,399,939	$1,172,146
Submit 122.21(r)(10,11,12)	2017					$150,000		$164,802	$142,160
Detailed Eng for CCC Conversion[1]	2018	$5,100,000						$5,709,726	$4,781,806
Convert Units 1 and 2 to CCC[1]	2019	$130,900,000	$5,000,000	$800,000				$169,948,362	$137,220,145
Estimated cost of outage loss	2019	$12,000,000						$13,689,908	$11,131,148
Monitor for EM - not required after CCC	N/A							$0	$0
								Total	
Total Scenario Cost								$196,704,997	$159,716,217

Note: Energy penalty is considered an O&M cost, but is listed separately for illustration.
[1] Detailed engineering costs are considered a Capital of closed cycle cooling system

Estimated Downtime	MTS FH&RS: Unit 1 will require downtime during Fall 2014 outage and Unit 2 in Spring 2014. Design is expected to take six months prior to construction which is expected to take 2 months. Construction of Units 1 and 2 cooling tower system is expected to take 15 months. Downtime is estimated to be approximately one month for each unit and occur during planned outage in spring 2019. Engineering will be completed in the preceding year, 2018. Other modifications listed should be able to be completed with minimum downtime.
Benefits	Highest cost option. Will achieve BTA for both IM and EM by reducing through-screen velocity < 0.5 fps for IM, and CCC for EM.

Appendix A

Technical Memorandum

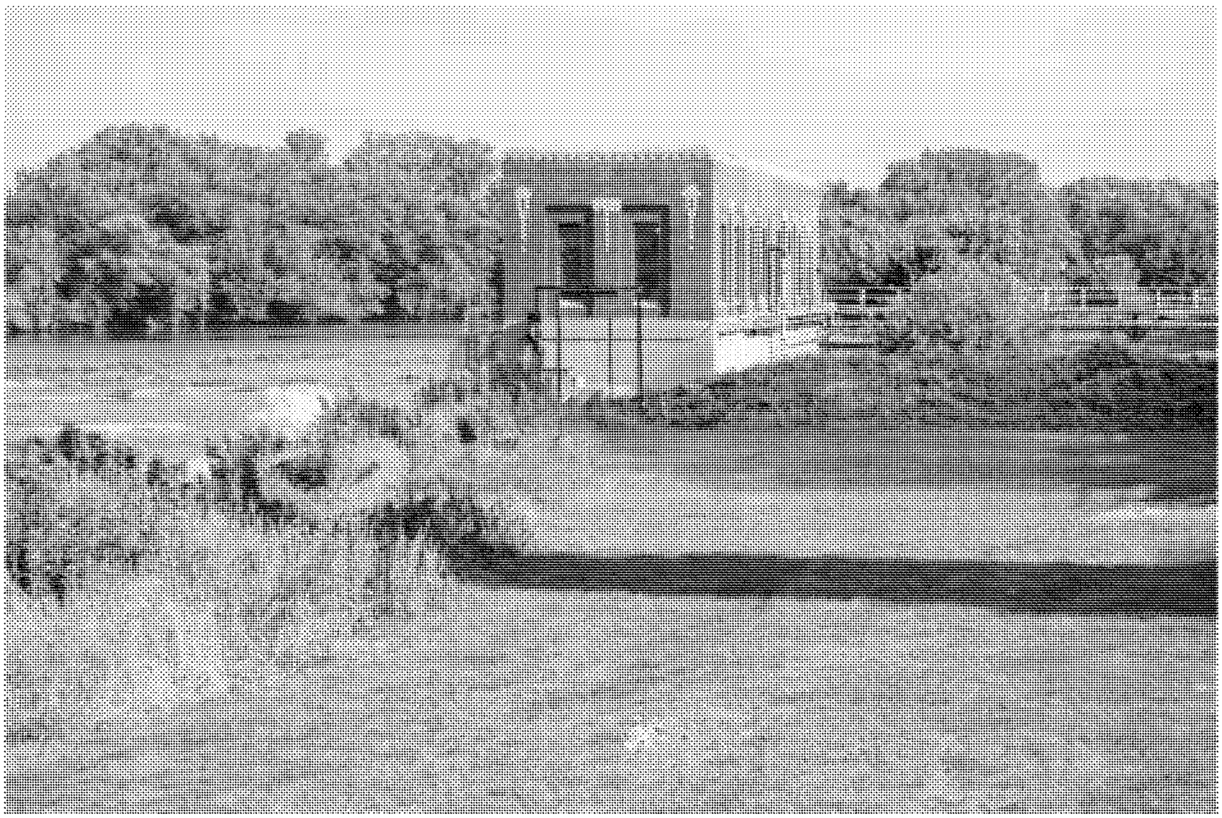
AECOM

Prepared for:
Indianapolis Power and Light

Prepared by:
AECOM
Chicago, IL
60220183
January 2012

316(b) Technical Memorandum

Indianapolis Power & Light



Prepared for:
Indianapolis Power and Light

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316(b) Technical Memorandum

Indianapolis Power & Light

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Contents

List of Appendices

1.0 Introduction

This 316(b) Technical Memorandum presents the existing and planned conditions at Indianapolis Power & Light's (IPL) Petersburg Station, Harding Street Station, and Eagle Valley Station, and examines the compliance options for these plants with the proposed Section 316(b) Rule published in April 2011 (proposed rule). This Technical Memorandum is intended to provide a summary of technical considerations that will be used to develop a compliance plan for efficient 316(b) compliance at IPL's generating fleet for the next several years.

It was recently announced that all of the units at the Eagle Valley Station and the four oldest units at the Harding Street Station are to be retired or otherwise taken out of service in the next several years. These anticipated operational changes were taken into consideration when developing this compliance plan and in some cases; the potential compliance path will affect the decision for future operational considerations.

2.0 Facility Operations

The three IPL facilities are located in central Indiana and withdraw cooling water from the White River. The three stations' locations follow:

- Petersburg Station – This station is located on the White River at River Mile 43.5. This is 1.5 miles downstream of the confluence of the East and West Forks of the White River, and 45 miles upstream of the Wabash River
- Harding Street Station – This station is located on the West Branch of the White River at River Mile 232
- Eagle Valley Station – This station is located on the West Branch of the White River at River Mile 200.5

This section provides a description of each of the current and anticipated operations at each plant, the cooling water intake structure configuration for each, and through screen velocities for the existing intakes. This information provides the basis for evaluation of compliance options and technology evaluations.

2.1 IPL Plant Current and Projected Operational Status

2.1.1 Operational Status

The following table presents the current operational status of the units at the three facilities.

Current Conditions			
	Eagle Valley	**Harding Street**	**Petersburg**
Generating Units	6 total	7 total, 5 active (1 and 2 retired) plus gas turbines	4 total
Active Coal Units	4 with once-through cooling: Units 3, 4, 5, and 6	3 Units Total: Units 5 and 6 once-thru cooling Unit 7 Closed cycle cooling	4 Units Total: Units 1&2 Once-thru cooling Units 3&4 Closed cycle cooling
Active Oil	2 with once-through cooling: Units 1 and 2 One emergency diesel generator	2 with once-through cooling: Units 3 and 4 (Units 1 and 2 retired) One emergency diesel generator	3 emergency diesel-fired generators
Gas Turbine	none	6 GT units, dry cooling	none
Total MW	364 MW	1196 MW	1725 MW

2.1.2 Projected 2015 Operational Status

IPL is planning to shut down the Eagle valley plant and a number of units at Harding Street. The Petersburg Station is intending to continue operating its 4 units in current mode. The analysis in this document is based on this understanding unless otherwise noted.

The following table presents the anticipated post-closure conditions at the three stations in 2015.

2015 Conditions			
	Eagle Valley	Harding Street	Petersburg
Generating Units	None	One, Unit 7 plus gas turbines	4 total
Active Coal	None	Unit 7 Closed cycle cooling	4: Units 1 and 2 Once-thru cooling Units 3 and 4 Closed cycle cooling
Active Oil	None	One emergency diesel generator	3 emergency diesel-fired generators
Gas Turbine	None	6 units, dry cooling	none
Total MW	None	463 MW,	1725 MW

2.2 Cooling Water Intake Structure (CWIS) Configuration

2.2.1 Existing CWIS Configuration

Each facility operates cooling water intake structures with bar racks and traveling screens. The following table presents data for the existing CWIS at the three facilities.

Current Conditions			
	Eagle Valley	Harding Street	Petersburg
Design intake Flow Rate	335.4 MGD	238.8 MGD	427.7 MGD
Average intake Flow Rate[1]	156.2 MGD	108.2 MGD	383.44 MGD
Forebays	6 forebays	2 separate CWIS: "CHU 1-4": 8 forebays - Units 1 thru 4; Units 1&2 bays not used "CWPH": 2 forebays for Units 5 and 6 Unit 7 make up water from junction box	Unit 1: 2 forebays Unit 2: 4 forebays Units 3 and 4 makeup water from 1&2 discharge Unit 2 ½ CCT during summer and low water level conditions draws makeup water from Unit 1 discharge.
Traveling Screens	12 - 96" wide, 3/8 openings	12 - 96" wide, 3/8 openings	6- 120" wide, 3/8 openings

Current Conditions			
	Eagle Valley	Harding Street	Petersburg
Circ Pumps	Units 1-3: 6 @ 15,500 gpm Unit 6: 2 @ 25,000 gpm Unit s 4 and 5: 4 @ 21,500 gpm	CHU1-4: 4 @ 16,100 gpm CWPH: 4 @ 24,750 gpm	Unit 1: 2 @ 56,000 gpm Unit 2: 4 @ 46,250 gpm
Calculated Design Through-Screen Intake Velocity	Units 1,2,3: 0.77 fps Units 4&5: 1.07 fps Unit 6: 1.24 fps	CHU 1-4: 0.97 fps CWPH: 1.17 fps	Unit 1: 1.60 fps Unit 2: 1.32 fps
Calculated Average Through-Screen intake Velocity[1]	Units 1,2,3: 0.36 fps Units 4&5: 0.50 fps Unit 6: 0.58 fps	CHU 1-4: 0.44 fps CWPH: 0.53 fps	Unit 1: 1.43 fps Unit 2: 1.18 fps
Installed technology	Traveling screens, no fish return	Traveling screens, no fish return	Traveling screens, no fish return

[1] Average flow rates are from water usage records from a three year period from 2008 through 2011.Average velocities were calculated using average flow rates.

[2] Petersburg Units 3 and 4 are not subject to the rule as the intake structure associated with these units does not meet the proposed definition of a CWIS (40 CFR 125.92).

2.2.2 Projected 2015 Cooling Water Use

As described above, there will be a number of unit closures by 2015. The anticipated changes to the facilities that will remain operational in 2015 include:

- Units 1-6 **Eagle Valley** will be retired. Therefore, this facility will no longer be subject the proposed regulation post 2015.
- Units 3-6 at **Harding Street** will be retired. Unit 7 will continue to operate closed cycle. The makeup water for Unit 7 will be supplied through the existing CWIS for Units 5 and 6 (CWIS 5&6) with lower capacity pumps.
- **Petersburg Station** will continue to operate all four existing units. However, United States Environmental Protection Agency (EPA) and Indiana Department of Environmental Management (IDEM) may require conversion to closed cycle cooling for Units 1 and/or 2 at the facility pursuant to the proposed 40 CFR 125.94(c). While the conversion of Unit 2 to CCC may be feasible, considering that it already operates a half-sized cooling tower, conversion of Unit 1 would be greatly disruptive to plant operations and costly. In either case, the change to closed cycle cooling is not expected to be complete by 2015; therefore, compliance with the draft rule is expected to be pursued under existing plant conditions.

The following table summarizes the expected post-closure water use at the facilities in 2015.

2015 Conditions			
	Eagle Valley	Harding Street	Petersburg (same as current conditions)
Design intake Flow Rate	N/A	23.0 MGD (One 16,000 gpm pump running, one pump in standby)	427.7 MGD
Average intake Flow Rate[1]	N/A	14.4 MGD (appx. amount of water actually needed for CT makeup and ash sluice)	383.44 MGD

[1] Average intake flow rate for Harding Street is based on the actual volume of water needed for plant operations. Though future conditions at Petersburg Station will eventually include operational modifications, these changes will not have been made by 2015, therefore, the intake volumes and velocities for Petersburg will be the same as existing conditions.

2.3 Visual Inspections of CWIS

On August 16 and 17, 2011, AECOM's engineer visited the three facilities to inspect the CWIS for the purpose of potential upgrades to the systems that could be considered to achieve compliance with the draft 316(b) rule. A summary of observations is presented in **Appendix A**.

2.4 Through Screen Velocities

2.4.1 Current Actual Through Screen Velocities

IPL previously calculated maximum design through screen and approach velocities for the CWISs at the three facilities. In addition, average through screen and approach velocities have been calculated based on operating data over the past three years. This section describes the calculation process and presents the design velocities and the calculated average actual velocities for the facilities.

AECOM calculated the through screen velocity, screen approach velocity, and bar rack approach velocity for each intake structure at the Eagle Valley, Harding Street and Petersburg facilities at actual intake flows as measured over the 3-year period from 2008 through 2011. Design and actual intake flows for each facility were provided by IPL.

The velocities at design intake flows were taken directly from the URS calculations (URS 2008a, 2008b, and 2008c) with one exception. AECOM reviewed the URS calculations for accuracy and found that one calculation at the Harding Street Units 5 and 6 intake was incorrect. The through screen velocity was calculated based on a 10 ft water depth while the approach velocities for the bar screens and traveling screen were based on an 8.25 ft water depth. Based on a review of CWIS drawings, AECOM determined that the bottom elevation of the CWIS was constant through the approaches and forebays and therefore, all three calculations should have had the same depth. AECOM determined that 10 feet water depth was the correct value for calculating all velocities for this intake. AECOM re-calculated the screen and bar rack approach velocities through this structure based on a 10 ft depth.

Once the URS calculations were determined to be correct (or corrected), actual intake velocities for each unit were calculated based on the assumption that the relationship between actual intake flow and design intake flow was equal for each unit in a given plant and that all other parameters were constant. In other words, if actual intake flows for the facility were 50% of the design intake flow for the facility we assumed that actual intake flows for each unit were also 50% of the design intake flow for that unit. To calculate velocities, we assumed that parameters such as water depth, screen width, and open area, were the same for design and actual scenarios. Intake velocity is equal to flow divided by area (V=Q/A). Therefore, if area remains constant, the change in velocity is directly proportional to the change in flow. As a result, if actual intake flow is 50% of design intake flow, the actual intake velocity was calculated to be 50% of design intake velocity. Note that the actual intake velocities are based on actual intake flows that include days of zero flow. Therefore, the average intake velocity during days when the unit is operating is likely to be significantly higher. The intake velocity when the unit is operating is likely to be considered the relevant measure by regulators.

Calculated Intake Velocities at Average Intake Flows at IPL Facilities

Current Conditions								
		CWIS						
Parameter	**Units**	Eagle Valley 1, 2 and 3	Eagle Valley 4 and 5	Eagle Valley 6	Harding Street 1&4	Harding Street 5&6[1]	Petersburg 1	Petersburg 2
Facility Actual Intake Flow (AIF)	CFS	241.7			167.4		593.3	
Facility Design Intake Flow (DIF)	CFS	518.8			368.6		661.6	
AIF as Proportion of DIF	-	0.466			0.454		0.897	
Through Screen Velocity DIF[2]	fps	0.77	1.07	1.24	0.97	1.17	1.60	1.32
Through Screen Velocity AIF[2]	fps	0.36	0.50	0.58	0.44	0.53	1.43	1.18
Screen Approach Velocity DIF[2]	fps	0.46	0.64	0.74	0.58	0.70	0.96	0.79
Screen Approach Velocity AIF[2]	fps	0.21	0.30	0.34	0.26	0.32	0.86	0.71
Bar Rack Approach Velocity DIF[2]	fps	0.35	0.49	0.57	0.40	0.53	0.83	0.68
Bar Rack Approach Velocity AIF[2]	fps	0.16	0.23	0.27	0.18	0.24	0.74	0.61

1. Velocities at DIF for Harding Street at AIF are adjusted from values reported by URS based mistaken wet depth. Used Wet Depth of 10 ft to calculate velocities.
2. Per CWIS.

2.4.2 Projected 2015 Through-Screen Velocities

AECOM has recalculated through screen velocities based on expected intake flow rates and CWIS layouts described in **Section 2.2.2** above.

2015 Conditions					
		CWIS			
Parameter	**Units**	Eagle Valley	Harding Street CWIS 5&6 (Unit 7 remains operational)	Petersburg 1	Petersburg 2
Facility Actual Intake Flow (AIF)	CFS	None	22.3	593.3	
Facility Design Intake Flow(DIF)	CFS	None	35.6	661.6	
AIF as Proportion of DIF	-	N/A	0.63	0.897	
Through Screen Velocity at DIF	fps	N/A	0.76	1.60	1.32
Through Screen Velocity at AIF	fps	N/A	0.48	1.43	1.18
Screen Approach Velocity at DIF	fps	N/A	0.46	0.96	0.79
Screen Approach Velocity at AIF	fps	N/A	0.28	0.86	0.71
Bar Rack Approach Velocity at DIF	fps	N/A	0.34	0.83	0.68
Bar Rack Approach Velocity at AIF	fps	N/A	0.22	0.74	0.61

The flows and velocities shown in the table in this section for Harding Street are based on required volumes provided by Harding Street personnel for operation after retirement of Units 3, 4, 5, and 6. This configuration assumes replacement of four 24,750 gpm with two 16,000 gpm pumps, one of which would operate continuously to provide sufficient water for plant needs, including cooling tower makeup water for Unit 7, while the other pump would remain in standby. Replacing the four 24,750 gpm pumps with one 16,000 gpm pump would reduce design through-screen velocity in each pump's bay from 1.17 fps to 0.76 fps. In order to reduce through-screen velocity further to below 0.5 fps, the intake area would need to be increased. This could be accomplished by opening the wall between two bays, doubling the screen area served by each pump. This would reduce maximum design through-screen velocity to the 0.38 fps shown in the table above.

Though future conditions at Petersburg Station will eventually include operational modifications, these changes will not have been made by 2015, therefore, the intake volumes and velocities for Petersburg will be the same as existing conditions.

3.0 Summary of Previous Biological Studies at IPL's Plant

3.1 Summary of Previous Studies

Many studies have been conducted in the White River and at the CWIS of the facilities since the mid-1970s. The following table presents a list of the studies that have been reviewed to determine the species of concern at the three stations.

	Eagle Valley	Harding Street	Petersburg
Previous Studies	1975 WAPORA I&E evaluation 1975 USGS 1978 WAPORA fish population & WQ assessment 1979 CDM 1985 WAPORA 316(b) demonstration 1987 ESE 1990 Hunter/ESE 2000 EA 2008 IM&E Study (conducted in 2007)	1975 USGS River Quality Assessment 1979 CDM 1985 WAPORA 316(b) Demonstration 1987 ESE Fish community & WQ survey 1990 Hunter/ESE 1992-1995 EA Evaluation of fish & macroinvertebrates 2000 EA 2008 IM&E Study (conducted in 2007)	1976 WAPORA Literature Review 1977 Indiana University Impingement Study 1979 CDM WQ Fish community study 1980 WAPORA 316(a) demonstration 1984 WAPORA bio survey 1990 Hunter/ESE fisheries & thermal study 2000 EA White River fish study 2008 IM&E Study (conducted in 2007)

3.2 Impingement and Entrainment Data

3.2.1 Impingement

The top ten species impinged at each facility during the 2008 Impingement Mortality and Entrainment Study are listed in the following tables and the estimated total annual impingement based on actual annual flow rates. The most common species impinged at the stations is Gizzard shad, an introduced forage fish of little to no ecological or commercial value. This species experiences high rates of mortality following impingement on Ristroph screens.

Eagle Valley

Species	Common Name	Number Impinged (2008 Study)	Percent Composition
Dorosoma cepedianum	Gizzard Shad	83	62%
Moxostoma anisurum	Silver Redhorse	11	8%
Lepomis macrochirus	Bluegill	9	7%
Ictalurus punctatus	Channel Catfish	6	5%
Lepomis humilis	Orange Spotted Sunfish	4	3%
Pimephales vigilax	Bullhead Minnow	3	2%
Moxostoma erythrurum	Golden Redhorse	2	2%
Lepomis cyanellus	Green Sunfish	2	2%
Moxostoma macrolepidotu	Shorthead redhorse	2	2%
Notropis spilopterus	Spotfin Shiner	2	2%
Total # fish impinged		**133**	**95%**
Estimated Total Annual Impingement		**1,152**	

URS, Eagle Valley Generation Station IM&E Report 2008

Harding Street

Species	Common Name	Number Impinged (2008 Study)	Percent Composition
Dorosoma cepedianum	Gizzard Shad	129	41%
Dorosoma petenense	Threadfin shad	91	29%
Lepomis macrochirus	Bluegill	34	11%
Lepomis humilis	Orange Spotted Sunfish	11	4%
Ictiobus bubalus	Smallmouth Buffalo	11	4%
Aplodinotus grunniens	Freshwater Drum	8	3%
Ictalurus punctatus	Channel Catfish	5	2%
Carpiodes cyprinus	Quillback carpsucker	4	1%
Labidesthes sicculus	Brook silverside	3	1%
Ictiobus bubalus	Smallmouth bass	3	1%
Total # fish impinged		**316**	**97%**
Estimated Total Annual Impingement		**3,085**	

URS, Harding Street Generation Station IM&E Report 2008

Petersburg

Species	Common Name	Number Impinged (2008 Study)	Percent Composition
Dorosoma cepedianum	Gizzard Shad	3,417	68%
Ictalurus punctatus	Channel Catfish	518	10%
Dorosoma petenense	Threadfin shad	238	5%
Carpiodes cyprinus	Quillback Carpsucker	107	2%
Aplodinotus grunniens	Freshwater Drum	81	2%
Ictalurus furcatus	Blue Catfish	59	1%
Pylodictis olivaris	Flathead catfish	59	1%
Pimephales vigilax	Bullhead Minnow	55	1%
Pimephales notatus	Bluntnose minnow	50	1%
Notropis atherinoides	Emerald shiner	45	1%
Total # fish impinged		**5,020**	**92%**
Estimated Total Annual Impingement		**42,075**	

URS, Petersburg Generation Station IM&E Report 2008

3.2.2 Entrainment

The following tables present the primary species that were observed in entrainment samples collected during the 2008 study and the estimated annual entrainment totals based on annual flow rates.

Eagle Valley

Species	Common Name	Number of Larvae Collected (2008 Study)	Estimated Annual Entrainment
	Unidentified	57	871,895
Catostomus commersoni	White sucker	40	461,507
Clupeidae sp.	Clupeidae sp.	36	607,314
Catostomidae sp.	Sucker sp.	35	682,859
Gambusia affinis	Mosquitofish	12	397,511
Cyprinidae sp.	Cyprinidae	8	301,203
Centrarchidae sp.	Centrarchidae	6	144,951
Carpiodes sp.	Carpsucker sp.	4	88,174
Lepomis macrochirus	Bluegill	1	150,495
Larval Total Entrained		**199**	**3,705,909**
Fish eggs collected		**1,555**	**52,040,145**
Total Entrained		**1,754**	**55,746,054**

URS, Eagle Valley Generation Station IM&E Report 2008

Harding Street

Species	Common Name	Number of Larvae Collected (2008 Study)	Estimated Annual Entrainment
	Unidentified	133	2,288,281
Clupeidae sp.	Herrings	102	1,690,006
Catostomidae sp.	Sucker sp.	59	2,279,753
Lepomis macrochirus	Bluegill	32	455,869
Centrarchidae sp.	Sunfish sp.	22	356,204
Sciaenidae sp.	Drums	21	349,183
Lepomis sp.	*Lepomis* sp.	8	107,094
Cyprinidae sp.	Carps and Minnows	7	105,324
Dorosoma cepedianum	Gizzard Shad	6	260,599
Larval Total Entrained		**404**	**8,324,220**
Fish eggs collected		**2,747**	**61,337,540**
Total Entrained		**3,151**	**69,661,760**

URS, Harding Street Generation Station IM&E Report 2008

Petersburg

Species	Common Name	Number of Larvae Collected (2008 Study)	Estimated Annual Entrainment
	Unidentified	35	736,847
Cyprinidae sp.	Cyprinidae	25	518,198
Dorosoma cepedianum	Gizzard Shad	16	297,291
Clupeidae sp.	Clupeidae sp.	16	325,225
Sciaenidae sp.	Sciaenidae	16	324,027
Centrarchidae sp.	Centrarchidae	14	293,309
Pimephales vigilax	Bullhead Minnow	13	247,672
Gambusia affinis	Mosquitofish	8	134,032
Dorosoma sp.	*Dorosoma*	8	147,863
Notropis sp.	*Notropis*	8	153,124
Larval Total Entrained		**188**	**3,757,397**
Fish eggs collected		**792**	**16,175,698**
Total Entrained		**980**	**19,933,095**

URS, Petersburg Generating Station IM&E Report 2008

4.0 Rule Requirements and Notable Obstacles

This section provides a brief overview of the proposed rule's requirements with potential to have significant implications for IPL.

4.1 Interim Compliance Prior to Operational Changes in 2015

Each IPL station has recently received, or is soon to receive its new NPDES permit with 5-year renewal cycle. This means that the final rule will be issued during the time that the plant's NPDES permits are active and that the earliest requirements of the 316(b) rule, as written in the draft rule, would be due in the middle of each plant's permit cycle. For the purposes of this report, it is assumed that existing permits will be modified to include new 316(b) requirements and all facilities will be required to submit the earliest documents within 6 months of the effective date of the new 316(b) Rule.

IPL is in the process of announcing the closure of several units including the entire Eagle Valley Station. The compliance paths described below assume that IPL will notify IDEM of the closure of the Eagle Valley Station and will request that IDEM not require compliance with the final 316(b) rule for that station.

4.2 Rule Requirements Specific to Each Plant

Section 316(b) of the Clean Water Act requires that NPDES permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures reflect the best technology available to minimize harmful impacts on the environment. Specifically, the 316(b) Rule is intended to reduce the impacts from withdrawal of cooling water by facilities to aquatic organisms through impingement and entrainment.

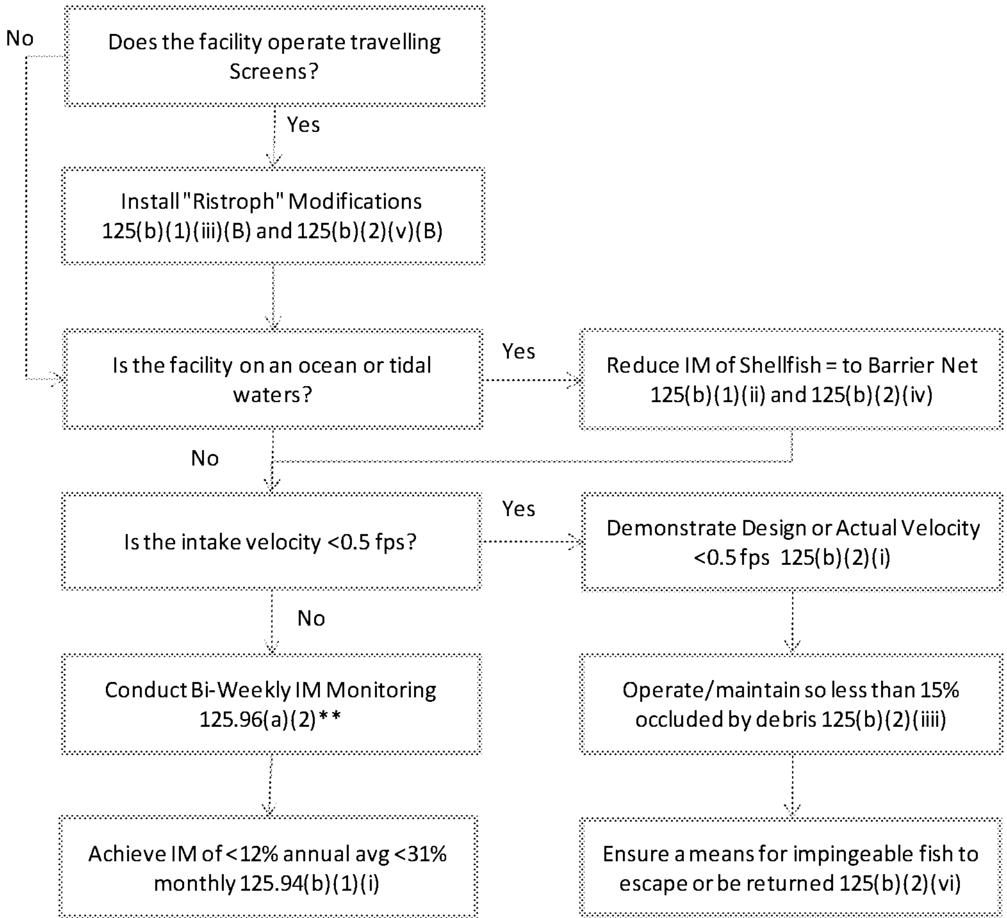
The rule defines separate paths toward compliance for impingement and for entrainment.

4.2.1 Impingement Compliance Path

The applicable requirements for impingement mortality are dependent on a number of intake and water body characteristics. The figure below provides an overview of the applicability of these requirements depending on site-specific characteristics.

Facilities with traveling screens are required to retrofit to a Ristroph modified traveling screens and install a fish return. If they have intake velocities that exceed 0.5 fps, they are also required to demonstrate that they meet the proposed Rule's impingement mortality numeric limitations.

Impingement Compliance Path



Under the proposed IPL operating conditions foreseen in 2015, the following impingement compliance path could be followed at the three plants.

Eagle Valley Station: IPL has studied the compliance options available to Eagle Valley Station considering the plans to close the plant by the end of 2015. These options are described in the memorandum prepared by Barnes & Thornburg included in **Appendix C**. These options include:

- Submit all documents required by the 316(b) rule and inform IDEM of closure plans as part of this submittal process;
- Inform IDEM of closure and request relief from submittal requirements by committing to closure dates (B&T determined this option to not be feasible; therefore this option will not be considered further);
- Inform IDEM of closure and request modification of NPDES permit to relieve plant of submittal requirements by committing to closure dates with a corresponding Agreed Order; or
- Request a variance from the 316(b) requirements based on hardship (B&T determined this option to not be feasible; therefore this option will not be considered further).

IPL will move forward with one of these options. The recommended compliance path for the Eagle Valley Station is presented in **Section 5.1** of the Compliance Strategy Plan.

In each of these cases, AECOM assumes that IDEM will not require retrofit and operation of new technologies to mitigate either impingement mortality or entrainment mortality. This conclusion is based on the fact that the proposed rule would not require retrofits until after the plant closure and that any retrofits would have a very poor cost-to-benefit ratio based on an operational period of only a year or two. While AECOM believes that this is a sensible outcome, we do note that IDEM will have to approve the approach.

Harding Street Station

Similar to the Eagle Valley Station options, Harding Street may consider requesting relief from some aspects of the 316(b) due to plans to close portions of the plant within the NPDES permit period. However, because the Harding Street Station will continue to operate Unit 7 and will continue to operate one of the existing CWISs, the station will be required to install modified traveling screens and to submit applicable reports and plans. The reporting options for Harding Street are discussed in the Barnes & Thornburg memo in **Appendix C**. These options include:

- Submit all documents required by the 316(b) rule and inform IDEM of closure plans as part of this submittal process;
- Inform IDEM of closure and request modification of NPDES permit to relieve plant of some of the submittal requirements by committing to closure dates via Agreed Order; or
- Request a variance from the 316(b) requirements based on hardship (B&T determined this option to not be feasible; therefore this option will not be considered further).

Harding Street Station will continue to operate Unit 7 and will continue to operate one of the existing CWISs to provide water to Unit 7 and other plant needs. Harding Street Station will be required to retrofit the traveling water screens to Ristroph-type screens with a fish return system. In addition, IPL will modify the Unit 5&6 intake so that the intake velocity is less than 0.5 fps. The recommended compliance path for the Harding Street Station is presented in **Section 5.2** of the Compliance Strategy Plan.

Petersburg Station

Petersburg Generating Station will continue to operate all four existing units. Currently Unit 1 operates with once-through cooling, Unit 2 operates with once-through cooling except in summer when it utilizes a half-capacity closed cycle cooling tower system, and Units 3 and 4 are fully closed cycle. AECOM identified three potential compliance scenarios for Petersburg facility under the proposed rule:

- continued operation under current conditions with the installation of MTS FH&RS;
- conversion of Unit 2 to fully closed cycle while Unit 1 remains once-through; or
- conversion of both Units 1 and 2 to fully closed cycle.

AECOM has assessed each of these cases and evaluated technical and operational modifications that would achieve or approach compliance with the proposed 316(b) rule for each. The recommended compliance path for the Petersburg Generating Station is presented in **Section 5.3** of the Compliance Strategy Plan.

Based on the facility water balance diagram, it is estimated that approximately 64,000 gpm (92 MGD), which includes estimates of makeup water for Units 1 and 2 cooling towers, would be needed to operate Petersburg Station with four units on closed cycle cooling. Water needs were determined from the facility water balance diagram and are presented in **Table 4.2-1** below. Replacing existing circulation pumps with lower capacity pumps and increasing intake area, if necessary, by opening more intake bays to the pumps would bring through screen velocity below 0.5 fps. Further engineering studies associated with this option in combination with operational needs would need to be conducted to determine if option is feasible.

Unit 1 circulating water pumps would provide sufficient flow to feed makeup water to Units 2, 3, and 4 as well as other plant needs, but the intake velocity would not be reduced to below 0.5 fps. Based on research into historic survival rates and fish species identified at the Petersburg facility (see **Section 3**), it is likely that modified Ristroph screens alone will not achieve compliance with the numeric performance standards, therefore seasonally deployed barrier nets were studied to determine if they could reduce the number of fish impinged, and in the event that the final rule would allow consideration of the reduction in impingement toward meeting the IM performance goals.

Table 4.2-1 Petersburg Facility Water Needs based on Water Balance Diagram

Water need	Water is drawn from	Maximum Instantaneous Water Flow (gpm)	Annual Average Flow (gpm)
Unit 3 CT makeup water	Discharge Canal	15,000	5,350
Unit 4 CT makeup water	Discharge Canal	15,000	5,350
Unit 3 FGD	Discharge Canal	820	550
Unit 4 FGD	Discharge Canal	820	550
Unit 2 CT makeup water (assumed to be the same as Units 3 and 4, though it should	Discharge Canal	15,000 (currently, the half CT draws 3,000 gpm)	5,350 (currently the half CT draws 750 gpm)

Water need	Water is drawn from	Maximum Instantaneous Water Flow (gpm)	Annual Average Flow (gpm)
be less because it is a smaller unit, 420 MW vs 575 MW)			
Unit 1 CT makeup water (assumed to be approximately half of the requirements for Units 3 and 4, because it is a smaller unit, 232 MW vs 575 MW)	Discharge Canal (assumed)	7,500	2,700
Seal Water	Discharge Canal	630	630
Strainer Backwash	Discharge Canal (returned directly to canal)	400	280
Quench Water	Discharge Canal (returned directly to canal)	110	25
	Total Need from Discharge Canal	**55,280**	**20,785**
The following flows are drawn from the circ water lines before the condensers			
Units 1 and 2 FGD	Before condensers	3,300	574
Units 1 and 2 Ash Handling	Before condensers	3,750	3,750
Water Treatment	Before condensers	640	240
Air Compressor Cooling water	Before condensers	unk. (taken from intake and returned after condensers, so no net loss of water from the canal, but need to make sure volume can be supplied from Unit 1 circ pumps alone)	unk.
	Total need before condensers	**7,960**	**4,564**
Total Water needed from Unit 1 Circ Pumps		**63,240**	**25,349**
Unit 1 Circ Pumps Capacity		**112,000**	**67,247 (65,760 discharged to canal)**

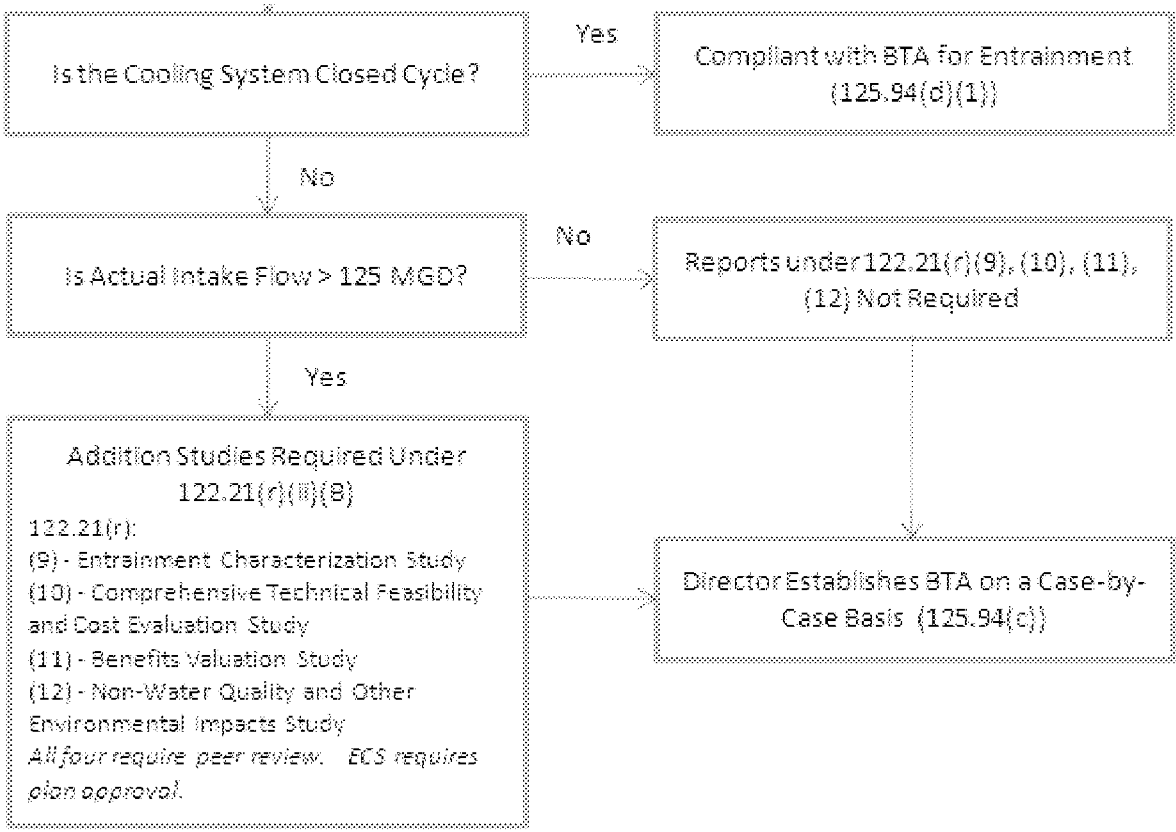
4.2.2 Entrainment Compliance Path

The proposed rule requires facilities with actual intake flows[1] (AIF) of greater than 125 MGD to submit a number of reports on entrainment mortality and options for reducing entrainment mortality. Based

[1] Actual intake flow is defined by the rule as the average volume of water withdrawn over the previous 3 years.

on these reports, the director will make a site-specific determination of BTA for reducing entrainment mortality. For a facility that withdraws less than 125 MGD, the rule does not require the submission of the entrainment mortality reports. However, the director must make a site-specific BTA determination. Facilities with closed cycle cooling are compliant with the rule's requirements for entrainment.

Entrainment Compliance Path



Under the proposed IPL operating conditions foreseen in 2015, after fleet modifications, the following entrainment compliance paths could be followed at the three plants.

Eagle Valley Station would be closed and therefore 316(b) compliance is not applicable.

Harding Street Station

Current actual intake flow over the years 2009-2011 for the plant is less than 125 MGD, therefore the Harding Street facility would not be required to submit the entrainment mortality reports under either reporting option described above. However, the director must make a site-specific BTA determination regarding entrainment mortality. Since the future plan is for Unit 7 to operate as closed cycle and all other units would be retired, Harding Street Station would be considered compliant with BTA for entrainment under the proposed rule.

Petersburg Station

Petersburg Station will continue to operate all four existing units. However, EPA/IDEM may require conversion to closed cycle cooling for Units 1 and 2 at the facility pursuant to the proposed 40 CFR 125.94(c). While the conversion of Unit 2 to CCC may be feasible, considering that it already operates a half-sized cooling tower, conversion of Unit 1 would be greatly disruptive to plant operations and costly. Conversion of both units to CCC would meet the requirement for EM BTA. If this is not feasible, other technologies could be proposed and tested for their effect on EM. Ultimately, IDEM will establish what would be considered BTA at the site based on a review of the costs and benefits of several options. The following options consider some technological solutions that could be considered by the IPL. Compliance options and recommended compliance path for the Petersburg Generating Station are presented in **Section 5.3** of the Compliance Strategy Plan.

5.0 Information Previously Developed by IPL/PAR Gaps

5.1 IPL 2008 Submittals

IPL submitted documents for each facility as required by NPDES permits in September 2008 that are consistent with the requirements of the proposed rule. These documents included:

- 122.21(r)(2) Source Water Physical Data,
- 122.21(r)(3) Cooling Water Intake Structure Data, and
- 122.21(r)(4) Impingement Mortality and Entrainment Characterization Study, submitted under Phase II Rule at § 125.95 (b)(3) and Indiana requirements at 40 CFR 401.14
- 122.21(r)(5) Cooling Water System Data

These documents have been reviewed for completeness and compliance with the requirements of the draft rule and for revisions that will be needed to reflect the anticipated changes to the operations of the IPL fleet due to unit closures.

5.1.1 Source Water Physical Data [122.21(r)(2)]

The proposed rule requires submission of a Source Water Physical Data including a narrative description of the source waterbody at the facility from which cooling water is drawn including hydrological and geomorphological features and location maps. The document submitted in 2008 appears to meet the requirements of the new rule under this section. No changes are anticipated for this document.

5.1.2 Cooling Water Intake Structure Data [122.21(r)(3)]

The proposed rule requires submission of Cooling Water Intake Structure Data including a narrative description of the configuration and operation of each cooling water intake structure at each facility, including design intake flows, hours of operation, water balance diagram and other information. The documents submitted in 2008 met the requirements of this section as it applied to the facilities at that time. No changes are anticipated for this document.

5.1.3 Impingement Mortality and Entrainment Characterization Study [122.21(r)(4)]

A study was conducted at each of the IPL stations in 2007 and submitted in 2008 to IDEM in fulfillment of the requirements of the Phase II rule described in 40 CFR 125.95(b)(3). These studies for contain the information required under Section 122.21(r)(4) – Source Water Baseline Characterization Study in the draft rule. The studies as written contain information required by the new rule including: list of species and relative abundance, identification of species most susceptible to I&M, identification of primary period of reproduction, seasonal daily activities, identification of threatened or endangered species, consultations with federal and state agencies, and methods of collection and quality assurance, and protective measures implemented to reduce I&M. This meets all of the requirements of the draft rule baseline biological characterization study.

These studies include a description of current protective measures and stabilization activities that have been implemented in a section comparing conditions at that time to the calculation baseline as described in the Phase II rule. No significant changes to the CWISs have been made since those reports were written. Though the 2008 reports do not include proposed protective measures anticipated in 2015 under the new IPL fleet operation, the rule requires description of measures that have been implemented, not proposed. Therefore, it appears that these studies should meet the requirements of the 122.21(r)(4) section of the draft rule, with possible minor revisions.

5.1.4 Cooling Water System Data [122.21(r)(5)]

The proposed rule requires submission of a Cooling Water System Data including a narrative description of the operation of the cooling water system and its relationship to cooling water intake structure. This includes the proportion of intake flow that is used for cooling, description of water reuse, description of reductions in total water withdrawals, number of days of operation, and other information. This document also includes design calculations and a description of existing impingement and entrainment technologies or operational measures in place and summary of their performance.

The documents submitted in 2008 met the requirements of this section as it applied to the facilities at that time.

6.0 PAR Issues of Concern Associated with the Submittal Requirements in the Draft Rule and PAR Compliance Options

6.1 2011 Draft Rule Submission Requirements

The draft rule requires additional information from existing facilities. In addition to the four documents described in the previous section, the following documents are required under the draft rule as written for power plant with DIF of 50 MGD or greater, within six months of final rule promulgation:

- 122.21(r)(6) Proposed IM reduction plan
- 122.21(r)(7) Performance Studies
- 122.21(r)(8) Operational Status
- 122.21(r)(9) Entrainment Mortality Data Collection Plan with peer reviewer identified (for non-closed cycle facilities with AIF >125 MGD)

Additionally, the following documents are required for non-closed cycle facilities with AIF greater than 125 MGD within five years of promulgation of the final rule:

- 122.21(r)(9) Entrainment Characterization Study
- 122.21(r)(10) Comprehensive technical feasibility and cost evaluation study
- 122.21(r)(11) Benefits Valuation Study
- 122.21(r)(12) Non-water quality and other environmental impacts study

6.1.1 Proposed IM Reduction Plan [122.21(r)(6)]

Existing facilities will be required to prepare and submit a Proposed Impingement Mortality Reduction Plan. This plan will identify the approach the facility proposes to use to meet the proposed IM requirements. This could include description of how the facility intends to directly measure impingement mortality through sampling, or demonstration that the maximum intake velocity is equal to or less than 0.5 fps and may include detailed engineering studies and pilot testing of possible IM BTA options.

An IM measurement plan would require description of the duration and frequency of monitoring, monitoring locations, organisms to be monitored, and the method by which naturally moribund organisms would be identified and taken into account. The plan would describe quality assurance/quality control methods and includes consideration of methods used in other studies performed in the study area.

Facilities may opt to demonstrate that the maximum intake velocity is equal to or less than 0.5 feet per second. This can be done by providing documentation demonstrating that the design intake velocity is less than 0.5 fps, or by providing a proposed method of demonstrating that maximum intake velocity will be below 0.5 fps.

The demonstration of maximum velocity would be a good option at the Harding Street Station where design intake velocity is expected to be reduced to below 0.5 fps in the 2015 configuration. However, in order to maintain the option to continue to operate Units 5 and 6 until a later date, Harding Street Station may choose to submit all documents and complete the impingement Monitoring study.

The Petersburg Station will not be able to be reduced below 0.5 fps before 2015 and should plan to submit an IM reduction plan.

Eagle Valley should be able to avoid submittal of this plan based on the decision to close the plant by 2015, if IDEM agrees. If not, Eagle Valley will submit the previously submitted documents with minor changes.

The Proposed IM Reduction Plan is required to be submitted within 6 months of promulgation of the final rule. The study would then be conducted and the results of the study submitted within 3.5 years of promulgation. It is assumed that monitoring would occur biweekly; 12 monitoring events would consistent of latent mortality monitoring; the remaining 14 monitoring events would consist of enumeration only. The rule does not dictate the frequency of sampling required, nor the number of years the sampling must be conducted.

6.1.2 Performance Studies [122.21(r)(7)]

Existing facilities will be required to submit a description of any biological IM or EM survival studies conducted at the facility and a summary of results. Studies conducted at other locations may also be included including justification as to why the data are relevant to the specific facility. New studies are not required to fulfill this requirement.

The 2008 IMECS study conducted at the IPL facilities, concentrated on collection of impingement and entrainment numbers and identification of species, not on survival or mortality. Data from those studies have already been submitted in 2008 and under 122.21(r)(4) described above. It does not appear that additional survival data are available for the IPL facilities for submittal under this requirement.

6.1.3 Operational Status [122.21(r)(8)]

Existing facilities will be required to submit a description of operational status of each unit including age of unit, capacity utilization for the previous 5 years, and major upgrades completed within the last 15 years, plans and schedules for decommissioning or replacement of units. This report would include description of expected flow reductions due to unit closures that will affect the units DIF and AIF and regulatory status.

This information is expected to be provided to IDEM and EPA in IPL's notification of the plans for 2015 and will be readily available for inclusion into Operation Status report within six months of rule promulgation.

6.2 Additional Application Requirements for Facilities with AIF Greater than 125 MGD

It is expected that the Petersburg facility improvements will not be implemented until well after the initial reporting period of the draft rule. Even if both Units 1 and 2 are planned to be converted to closed cycle cooling, the Petersburg Station would still be required to submit the reports and conduct studies required based on current conditions. Harding Street's current AIF is less than 125 MGD, therefore it should be exempt from these reporting requirements. Eagle Valley Station would be required to submit these documents under its current operating conditions, however, Eagle Valley is expected to be closed before the due dates of these reports, therefore, these reports and studies would no longer be applicable.

6.2.1 Entrainment Characterization Study Plan [122.21(r)(9)]

Within six months of promulgation of the final rule, existing facilities with AIF of greater than 125 MGD will be required to submit a plan for collecting entrainment mortality data and include identification of a peer reviewer and description of the peer review process. This entrainment mortality data collection plan would include the duration and frequency of monitoring, monitoring locations, a taxonomic identification of the sampled or evaluated biological assemblages, organisms to be monitored, method by which latent mortality would be identified, and documentation of all methods and QA/QC procedures for sampling and data analysis.

The entrainment characterization plan must be peer reviewed and begin implementation within six months of submittal of the plan and within one year of promulgation of the rule. The results of the completed study are required to be submitted within 4 years of promulgation.

6.2.2 Comprehensive Technical Feasibility and Cost Evaluation Study [122.21(r)(10)]

Within 5 years of promulgation, facilities with AIF greater than 125 MGD, must submit a comprehensive technical feasibility and cost evaluation study of candidate entrainment mortality control technologies being considered for the facility. The study must include an evaluation of technical feasibility of closed cycle recirculating cooling systems and fine mesh screens with mesh size 2 mm or smaller. After submission, the director may require review of other entrainment mortality control technologies. The study must include engineering cost estimates of all technologies considered and the report must be peer reviewed.

6.2.3 Benefits Valuation Study [122.21(r)(11)]

Within 5 years of promulgation, facilities with AIF greater than 125 MGD must submit an evaluation of the magnitude of water quality benefits, both monetized and non-monetized, of the candidate entrainment mortality reduction technologies and operational measures evaluated in the comprehensive technical feasibility and cost evaluation study under 122.21(r)(10). This evaluation must include a description of the incremental changes in the numbers of fish and shellfish lost due to IM and EM, identification of the basis of monetized values used, discussion of mitigation measures already completed, and identification of other benefits t the environment and local communities. The benefits valuations study must be peer reviewed.

6.2.4 Non-Water Quality and Other Environmental Impacts Study [122.21(r)(12)]

Within 5 years of promulgation, facilities with AIF greater than 125 MGD must submit a study of the changes in non-water quality factors and other environmental impacts attributed to each technology and operation measure evaluated under 122.21(r)(10). This study must include estimates of changes to energy consumption, changes to thermal discharges, changes to air pollution emissions and human health impacts associated with those emissions, changes in noise levels, impacts on safety, impacts to grid reliability, impacts to facility reliability, significant changes in consumption of water through evaporation, and a discussion of reasonable attempts to mitigate these factors. This study must be peer reviewed.

6.3 Detailed Engineering Study

Detailed engineering studies will be required to further define the scope and costs of technologies expected to be implemented at the facilities under the proposed 2015 operating conditions. These studies are required indirectly by 122.21(r)(6) for impingement and 122.21(r)(10) for entrainment control technologies.

The detailed engineering study will include a conceptual design basis and engineering drawings of proposed technologies for the specific site conditions at Petersburg and Harding Street Stations. The design will be of sufficient detail develop accurate costs for construction.

The expected cost to prepare the detailed engineering study is estimated to be $100,000 for Petersburg and $60,000 for Harding Street.

6.4 Anticipated Cost and Schedule for Additional Reports and Studies

Table 6.1 lists the documents and studies that were described above and identifies which of the IPL facilities would be required to submit reports or conduct studies under various scenarios. The table also provides the estimated costs for those reports and associated studies. Costs shown take into consideration those reports that were previously submitted and meet or partially meet the requirements under the draft rule.

It has not been determined whether EPA and IDEM will require complete submittal of all of the 122.21 documents for facilities that plan to shut down during the permitting cycle (Eagle Valley, Harding Street Units 3-6). Even if IPL is told to submit all or some of these reports, it is likely that the agencies would not require starting the monitoring studies required under 122.21(r)(6) and (9) at Eagle Valley station. Therefore, no costs are presented for completing the monitoring studies at Eagle Valley.

Under existing plant conditions, each of the I IPL stations would be required to submit all of the initial 122.21 documents. If EPA and IDEM provide relief for stations with unit closures, Eagle Valley may not need to submit any documents, and Harding Street and Petersburg would submit a reduced number of documents. The costs and schedule for this second scenario is presented later in this section.

The general expected costs for these reports and studies under existing conditions are estimated and presented in the following table. Plant-specific reporting costs and schedules have been developed based on AECOM's recommended compliance strategies and are presented in **Section 3.2** of the Compliance Strategy Plan.

Facility	Reports Due	Cost of Reports	Studies Required	Cost of Studies[2]
Eagle Valley,	122.21(r)(2) through (9)	$20,000[1]	None	$0
Harding Street	122.21(r)(2) through (8)	$55,000	122.21(r)(6)	$250,000[3]
Petersburg	122.21(r)(2) through (9), (10), (11), and (12)	$230,000	122.21(r)(6) and (9)	$400,000/year frequency to be determined

1. Assume that these studies are very simple that describe the fact the facility is shut down. If agreement can be made with IDEM to relieve EV of reporting requirement, cost would be $0.

2. Estimated implementation costs are highly dependent on nature and frequency of monitoring required by NPDES director, scale of facility, and number of organisms impinged. Costs presented are based on assumption that monitoring would occur biweekly; 12 monitoring events would consistent of latent mortality monitoring; the remaining 14 monitoring events would consist of enumeration only.
3. This assumes that Harding Street will be required to conduct impingement monitoring studies due to continued operation of CWIS 5&6 under current flow configuration until a final plan for future operations is developed. If velocity is reduced to <0.5 fps, only need to prove that, cost drops to $15,000.

Table 6.1 Planning Cost Estimates for Reports Under 40 CFR 122.21(r) in the Proposed Existing Facility Rule
These are only approximate estimates for budgetary purposes +/- 30%.

Section	Title	Summary/Time Frame	Available from Phase II Effort?	Applicable at IPL Facilities Current Conditions	Approximate Cost per Plant
(2)	Source water physical data	Maps and description of source water. Area influence of intake. 6 months from promulgation.	Yes – no modification needed	EV HS P	$0
(3)	Cooling water intake structure data	Engineering drawings, water balance, summary of operation and position. 6 months from promulgation.	Yes - Will need to be rewritten to describe expected post-2015 conditions	EV HS P	$10,000
(4)	Source water baseline biological characterization data	Summary of taxa subject to impingement and entrainment including seasonal variation and listed species. Document public participation and data gaps. List existing protective measures. Cost estimate is based on the assumption that existing data are used and no field work is necessary. 6 months from promulgation.	Yes – 2008 URS IM&E Study provides most of the needed information. Anticipate short document with previous study attached.	The applicability of this requirement is not clear in the proposed rule. It may only be required for "new facilities". However, assumed to be required for all 3 plants	$10,000
(5)	Cooling water system data	Narrative description of the cooling system including any water reuse or water reduction. Days of operation and proportion of source water withdrawn. List of existing protective measures and a summary of their performance. 6 months from promulgation.	Yes - Will need to be rewritten to describe expected post-2015 conditions	EV HS P	$5,000

Table 6.1 Planning Cost Estimates for Reports Under 40 CFR 122.21(r) in the Proposed Existing Facility Rule
These are only approximate estimates for budgetary purposes +/- 30%.

Section	Title	Summary/Time Frame	Available from Phase II Effort?	Applicable at IPL Facilities Current Conditions	Approximate Cost per Plant
(6)	Impingement mortality reduction plan[3]	Define approach used to meet impingement mortality performance goals. Include nature of performance monitoring including identification of species of concern and methods for evaluating latent mortality (if appropriate). 6 months from promulgation	No - Procedures will be similar to 2008 study, but will include survivability and latent mortality assessment.	EV[1] HS[2] P	HS \$5,000 plan and \$15,000 demonstration of V<0.5fps; or \$20,000 plan and \$250,000/yr implementation Pete \$20,000 plan and \$250,000/yr impl[2]
(7)	Performance studies	Summary of biological data that were conducted in the past or at other facilities. 6 months from promulgation	Should be able to use previously collected data	EV HS P	\$5,000
(8)	Operational status	Description of the operational status of each "generation, production, or process unit". Include rates of production for the last five years and anticipated production plans. 6 months from promulgation	Should be same as what IPL provides IDEM and EPA describing the plant closures, with some extra operational information	EV HS P	\$5,000
(9)	Entrainment characterization study	Plan to characterize entrainment mortality including duration, frequency, and location of monitoring. Identification of species of concern, QA/QC measures, and methods for characterizing latent mortality. Provide peer review. 6 months from promulgation, peer reviewer identified. Peer reviewed in one year. Complete study in 4 years.	No	EV[1] P	\$25,000 (plan) \$150,000/yr (implementation)[3]

Table 6.1 Planning Cost Estimates for Reports Under 40 CFR 122.21(r) in the Proposed Existing Facility Rule
These are only approximate estimates for budgetary purposes +/- 30%.

Section	Title	Summary/Time Frame	Available from Phase II Effort?	Applicable at IPL Facilities Current Conditions	Approximate Cost per Plant
(10)	Comprehensive technical feasibility and cost evaluation study	Evaluation of the technical feasibility and costs of entrainment control technologies. Must include evaluation of closed cycle cooling and addition of fine mesh screens. Peer review is required. 5 years after promulgation	No	EV – N/A Pete	$50,000
(11)	Benefits valuation study	Evaluation of the magnitude of monetized and non-monetized benefits of potential impingement mortality and entrainment control measures. Peer review is required. 5 years after promulgation	No	EV – N/A Pete	$60,000
(12)	Non-water quality and other environmental impacts study	Site-specific discussion of changes in non-water quality factors and other environmental impacts associated with each technology and measure considered under (r) 10. Peer review is required. 5 years after promulgation	No	EV – N/A Pete	$40,000

Notes:

1. Assumes that Eagle Valley will not be required to perform any monitoring studies, even if it is required to submit plans.
2. Assumes Harding Street will only need to demonstrate that design intake velocity is below 0.5 fps for impingement mortality reduction.
3. Estimated implementation costs are highly dependent on nature and frequency of monitoring required by NPDES director, scale of facility, and number of organisms impinged. Costs presented are based on assumption that monitoring would occur biweekly; 12 monitoring events would consistent of latent mortality monitoring; the remaining 14 monitoring events would consist of enumeration only.

7.0 Screening Evaluation to Identify Feasible Cost-Effective Technology/Operational Measures

The potential feasibility of many of the technologies commonly used or studied for use in reducing IM and E at cooling water intake structures was reviewed for this study. The following sections describe the technologies that were determined to be potentially feasible at the IPL stations for reducing impingement and/or entrainment mortality. The complete review of other technologies previously considered is presented in **Appendix B**. The technologies were considered under the proposed 2015 operating scenario with Eagle Valley Station closed and Harding Street operating only Unit 7 with closed cycle cooling. AECOM notes that there are many factors that can support the elimination of closed cycle cooling as BTA for Petersburg Unit 1 including costs relative to benefits, other adverse environmental impacts, feasibility, space constraints, water consumption, and changes in effluent quality. For this analysis, Petersburg Station is considered under two scenarios; one with Unit 2 converted completely to closed cycle cooling and Unit 1 remaining once-through, and a second scenario where both Units 1 and 2 are converted to closed cycle cooling.

7.1 Capital Costs and Economic Feasibility

Capital costs were developed using information obtained from vendors, information available in the EPA Technical Development Document for the Rule (TDD) (USEPA 2004), general engineering references, and costs obtained from other plant operators and records:

- EPA Technical Development Document (TDD) for the Final Section 316(b) Phase II Existing Facilities Rule, February 2004. (EPA-821-R-04-007);
- EPA Technical Development Document for the Section 316(b) Phase II Existing Facilities Proposed Rule, April 2002. (EPA-821-R-02-003);
- Cost estimates and/or installed costs for similar equipment obtained from vendors and other operating plants; and
- Brayton Point Plant 316(b) Demonstration (USGen New England Inc.).

The costs developed are approximate; however, they do account for a number of site-specific factors (e.g., distance from the river to the plant, configuration and capacity of CWIS, etc.). Available costs were adjusted to account for size and capacity differences as follows:

- proportionally for components/equipment whose costs were judged to be proportional to size (e.g. pipe length); and
- by the 6/10ths rule[2] for those components whose costs were judged to not be directly proportional to size (e.g. pumps).

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[2] The 6/10ths rule or factor is a logarithmic relationship between equipment size and cost. In simple form, Cn = Cxr^0.6, where Cn = cost of new equipment, C = cost of existing equipment (or a known cost), and r = the ratio of the new to existing capacity or size. [Reference: Chilton, C.H., "Six Tenths Factor," *Chemical Engineering*, April 1994, pp. 112-114.]

The following factors were applied, where appropriate:

- 10% allowance for indeterminates (AFI), a contingency[3] on costs of the items included;
- 30% contingency[4] to address unforeseen items, especially with regard to a plant retrofit; and
- Escalation based on the time frame of the basis cost estimate. Since the basis cost year varied, estimated costs were escalated using the ENR Construction Cost Index.

Additional O&M, pilot testing, and downtime costs would likely be incurred for many of the alternatives. These costs are considered for those technologies with some potential to be feasible and effective.

While these cost estimates are based on consideration of a number of site-specific factors, they are still approximate. In many cases, the costs rely on cost equations from the EPA TDD that may be out of date or not applicable. In addition, rapid changes in the price of commodities and energy have the potential to impact the estimates that are presented. Also most of these sources represent the national average costs and do not take into account regional differences in material and labor costs. Therefore, while the costs presented here are useful for considering the relative costs of various alternatives, the actual costs of implementing any of these alternatives could be substantially higher and will need to be determined as part of a detailed engineering study for each facility chosen compliance option(s).

7.2 Modified Traveling (Ristroph) Screens

The draft rule as written requires installation of Ristroph screens with fish return at all existing facilities with traveling screens. Therefore, Ristroph screens were considered for both Harding Street and Petersburg Stations under the proposed 2015 operating conditions.

<u>Overview</u>

This alternative consists of replacing the existing traveling screens with modified Ristroph screens to decrease the mortality of organisms that are impinged. The new screens would include fish buckets on the screens, low and high pressure spray wash systems and separate debris and fish return troughs. The discharge point of the fish return trough would be selected in order to minimize the potential for re-impingement in the intake flow or exposure to the heated discharge. Depictions of Ristroph traveling screen systems are presented in **Appendix D**.

<u>Technical Feasibility</u>

Ristroph screens can typically be installed directly into the slots for standard traveling screens. Therefore, installing Ristroph screens at the IPL facilities would be feasible. It is assumed that full traveling screen hardware replacement would be required at both plants. Traveling screen replacement could likely be accomplished without unit downtime by installing the modified screens during scheduled outages and/or by isolating individual bays for installation and keeping other bays open during replacement.

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[3] The 10% AFI and 30% contingency were both chosen based on past experience and engineering judgment for this level of cost estimate.

There could be significant issues with construction and maintenance of fish return troughs at the IPL facilities due to the required length, fluctuations in river level, and freezing conditions. These concerns have potential to make the installation of an effective fish return infeasible or extremely challenging. A detailed engineering study should be conducted to determine the best design for fish return at the IPL stations.

<u>Predicted Survival Rates with Ristroph Screens</u>

Facilities with intake velocities of greater than 0.5 fps are required to meet impingement mortality limitations of 12% on an annual basis and 31% on a monthly basis. These values correspond to post-impingement survival rates of 88% and 59% respectively. Each of the IPL stations currently has design intake velocity of greater than 0.5 fps, therefore, we estimated the effectiveness of Ristroph screen modifications at IPL's facilities.

To estimate the effectiveness of Ristroph screen modifications, species specific data from the EPRI report "Evaluating the Effects of Power Plant Operations on Aquatic Communities" (EPRI 2003a) were reviewed. This report contains impingement survival rates for more than 300 taxa compiled from 71 studies conducted at 35 steam electric plants. Both initial and extended survival rates are reported. Only data for extended survival were used in this analysis, since this measure more closely represents actual mortality attributable to impingement.

There are important caveats for interpreting the data from the EPRI report. The data were collected over a wide range of environmental and site-specific conditions that are likely to impact survival. These include water temperature, air temperature, the presence or absence of anti-fouling chemicals, the configuration of the fish return trough, and the type and operation of the rotating screen. With the exception of a few parameters on screen configuration and operation, these variables are unknown, and as a result, cannot be controlled in the analysis. In addition, the methodology used for the studies varies. For example, different studies measured extended survival over time periods ranging from 24 to 102 hours. These variations in conditions and methodology are likely to have substantial impact on the measured survival rates. Despite these variables, the data represent the best compilation of survival rates available, and so were used for this study.

Survival following impingement on Ristroph Modified screens varies considerably between species. Some species have survival rates of greater than 90%, while others experience greater than 50% mortality. Therefore, considering the survival of the species potentially impinged at each facility was important when characterizing the effectiveness of the alternatives considered. For example, gizzard shad was the most common fish impinged at the IPL stations in the 2008 impingement study (41% of individuals collected at Harding Street and 68% at Petersburg). Gizzard shad has a low predicted survival rate of 48% which pulls down the overall impingement survival rate at the stations. However, there is potential that the permit writer would determine that gizzard shad is not a species of concern. In this case, the mortality of this species may not need to be considered when evaluating compliance with the impingement mortality limitations.

Based on this review, the facilities are not projected to meet the proposed rule's impingement mortality limitations with the installation of Ristroph screens if all impinged species are considered species of concern. Survival based on this preliminary assessment is estimated to be approximately 55% at each of the facilities. This corresponds to an impingement mortality rate of 45%, well above the draft Rule's IM limitations.

Based on conversations with EPA and information provided in the Technical Development Document, the proposed Rule's impingement mortality limitations are intended to be applied to only species of concern. However, this is not clear in the regulatory text in the proposed rule. There is potential that the final rule will more clearly indicate that any numeric performance standards only apply to species of concern. If this is the case, there is potential that IPL could advocate for excluding gizzard shad from the species of concern. AECOM has estimated that if gizzard shad, threadfin shad and other forage species are removed from consideration in IM survivability rates, the survivability of the hardier species could approach 85%, which is within the margin of error of the performance goal. If IDEM accepts this position, compliance with the performance standard using Ristroph modified screens might be achieved.

Eagle Valley

Species	Common Name	Percent Composition	Extended Survival[1]	Standard Deviation	Weighted Extended Survival[2]	Notes
Dorosoma cepedianum	Gizzard Shad	62%	48%	36%	32%	
Moxostoma anisurum	Silver Redhorse	8%	na	na	-	
Lepomis macrochirus	Bluegill	7%	94%	8%	6%	
Ictalurus punctatus	Channel Catfish	5%	82%	14%	4%	Survival data for white catfish used as a surrogate
Lepomis humilis	Orange Spotted Sunfish	3%	79%	22%	2%	Survival data are for sunfish (Centrarchidae) family
Pimephales vigilax	Bullhead Minnow	2%	84%	0%	2%	Survival data are for minnow (Cyprinidae) family
Moxostoma erythrurum	Golden Redhorse	2%	na	na	-	
Lepomis cyanellus	Green Sunfish	2%	79%	22%	1%	Survival data are for sunfish (Centrarchidae) family
Moxostoma macrolepidotu	Shorthead redhorse	2%	na	na	-	
Notropis spilopterus	Spotfin Shiner	2%	84%	23%	1%	Survival data for spottail shiner used as surrogate
Total		**93%**			**59%**	

Notes:

Species susceptible to impingement are from 2008 URS study

All survival data is from EPRI 2003

Surrogates used for species where species specific data was unavailable or extremely limited

[1] Data is for Ristroph modified screens rotated continuously

[2] Survival is weighted based on the proportion of the population each species represents

Harding Street

Species	Common Name	Percent Composition	Extended Survival[1]	Standard Deviation	Weighted Extended Survival[2]	Notes
Dorosoma cepedianum	Gizzard Shad	41%	48%	36%	19%	
Dorosoma petenense	Threadfin shad	29%	48%	36%	14%	Survival data for gizzard shad used as a surrogate
Lepomis macrochirus	Bluegill	11%	94%	8%	10%	
Lepomis humilis	Orange Spotted Sunfish	4%	79%	22%	3%	Survival data are for sunfish (Centrarchidae) family
Ictiobus bubalus	Smallmouth Buffalo	4%	na	na	-	
Aplodinotus grunniens	Freshwater Drum	3%	na	na	-	
Ictalurus punctatus	Channel Catfish	2%	82%	14%	1%	Survival data for white catfish used as a surrogate
Total		**92%**			**55%**	

Notes:

Species susceptible to impingement are from 2008 URS study

All survival data is from EPRI 2003

Surrogates used for species where species specific data was unavailable or extremely limited

[1] Data is for Ristroph modified screens rotated continuously

[2] Survival is weighted based on the proportion of the population each species represents

Petersburg

Species	Common Name	Percent Composition	Extended Survival[1]	Standard Deviation	Weighted Extended Survival[2]	Notes
Dorosoma cepedianum	Gizzard Shad	68%	48%	36%	32%	
Ictalurus punctatus	Channel Catfish	10%	82%	14%	8%	Survival data for white catfish used as a surrogate
Dorosoma petenense	Threadfin shad	5%	48%	36%	2%	Survival data for gizzard shad used as a surrogate
Carpiodes cyprinus	Quillback Carpsucker	2%	100%	na	2%	Survival data for white sucker used as a surrogate
Aplodinotus grunniens	Freshwater Drum	2%	na	na	-	
Ictalurus furcatus	Blue Catfish	1%	82%	14%	1%	Survival data for white catfish used as a surrogate
Pylodictis olivaris	Flathead catfish	1%	82%	14%	1%	Survival data for white catfish used as a surrogate
Pimephales vigilax	Bullhead Minnow	1%	84%	0%	1%	Survival data are for minnow (Cyprinidae) family
Pimephales notatus	Bluntnose minnow	1%	84%	0%	1%	Survival data are for minnow (Cyprinidae) family
Total		**91%**			**55%**	

Notes:

Species susceptible to impingement are from 2008 URS study

All survival data is from EPRI 2003

Surrogates used for species where species specific data was unavailable or extremely limited

[1] Data is for Ristroph modified screens rotated continuously

[2] Survival is weighted based on the proportion of the population each species represents

E Effectiveness

This alternative would not be effective at reducing E. The Ristroph screens considered under this assessment have standard size mesh. Fine mesh screens are discussed in the following section.

Capital Costs and Economic Feasibility

The total estimated rough order of magnitude (ROM) costs for installing Ristroph modified traveling screens and associated equipment is $1.6MM for installation on 2 screen bays on CWIS 5&6 at Harding Street, and $3.4MM for the six screens bays of Units 1 and 2 CWIS at Petersburg Station. This capital cost includes the cost of replacing traveling screen equipment to accommodate Ristroph modifications, the cost of the Ristroph equipment (screens, buckets, low pressure spray wash pumps), and construction of a fish return trough. The costs assume a relatively simple construction and installation of a 500 ft long fish return at Petersburg and a 600 ft long fish return at Harding Street. AECOM has included an additional 30% to the cost of the fish return to account for heating of the fish return flume to avoid freezing and measures to protect the fish return flume from debris or ice damage. These costs do not account for any modification of the screen wells, screen house, or related structures.

Ristroph screens would impose a higher operating and maintenance cost than the existing traveling screens. These costs are related to the assumption that the modified traveling screens would be rotated continuously whenever the unit is operation. Under current operations, the screens are rotated on an intermittent basis. The increase in rotation frequency leads to increased power use and can lead to more frequent screen and pump rebuilds. Operation and maintenance costs at the Harding Street Station are estimated to be approximately $52,000 per year above the cost of maintaining the current traveling screen system. O&M costs for Petersburg Station are estimated to be $190,000 above the cost of maintaining the current traveling screen system. These costs include the increased power draw associated with additional spray wash pumps and continuous screen rotation and assume that increased costs associated with screen and pump rebuilds would be incurred based on the continual rotation of the screens.

Additional costing details are provided in Section 4.2 of the Compliance Strategy Plan.

Conclusions

This technology is required by proposed section 125.94(b), therefore it will be required to be installed at both IPL stations. This alternative would be unlikely to meet the proposed rule's impingement mortality numeric limitations for all species impinged. However, there is some potential that the performance relative to the rule's goals would be substantially higher if IDEM concluded that Gizzard Shad and other forage species are not considered species of concern in calculating survival rates. In addition, there is potential that the final rule will be structured to allow facilities that install Ristroph modified screens to be compliant without demonstrating achievement of a numeric performance standard.

7.3 Barrier Nets

Overview

Barrier nets are wide-mesh (generally 1/4 or 3/8 inch) nets that are placed in front of the intake structure entrance to exclude fish. These are typically either strung between pilings or suspended from floats and anchored on the bottom. Organisms are generally able to avoid impingement on the barrier nets due to low through-net velocities (often less than 0.1 fps). Barrier nets in northern climates are typically installed on a seasonal basis. They are frequently installed during peak migration periods and removed during the winter months due to ice damage concerns. Barrier nets were reviewed for applicability at the Petersburg Station to be used in conjunction with modified Ristroph screens to reduce losses to impingement mortality.

As drafted the proposed rule does not provide credit for the reduction in impingement rates that barrier nets may achieve. This may change as the rule is finalized. Until that happens, AECOM believes that use of barrier nets should not be considered as a means of compliance with the rule.

Technical Feasibility

Construction of barrier nets at the IPL facilities is potentially feasible however ice conditions would require that they are removed on a seasonal basis. However, achieving the recommended through-net velocity of 0.06 fps (USEPA 2004) is not feasible at the Petersburg facility. Achieving the recommended velocity would require approximately net approximately 1,100 feet long for which there is not space at the Petersburg Station. The space available is approximately 135 feet, based on rough measurement from maps. Given the existing water depth, this configuration would result in a through-net velocity of 0.2 fps.

This intake velocity of 0.2 fps would likely make maintaining the integrity of the debris net challenging. The debris and ice loading at the intake would increase these challenges. In addition, loadings of green algae have potential to impact the operation of the net. Therefore, such a net would need to be seasonally deployed and may require a significant investment to maintain it in an effective manner.

IM Effectiveness

Barrier net effectiveness at reducing impingement varies. Reductions in impingement with barrier nets can reach 95%; however, it is not unusual for performance to be less than 60% (EPRI 1999). Reduced performance appears to be related to tears in the net material and gaps between the net and bottom that allow organisms to pass through or under the net. These issues are likely to be prevalent at the Petersburg facility due to the high debris loads and high through net velocity.

These effectiveness estimates are for the period that the barrier net is deployed. Ice conditions would require that barrier nets be installed only during the ice-free period. Heavy debris loading would also require periodic removal of the nets. Past impingement monitoring data suggest that the periods of greatest impingement are during the cold weather months, when the nets would be removed to avoid ice damage. This significantly reduces the potential benefits of barrier nets.

The combination of seasonally deployed barrier nets and modified traveling screens may reduce impingement rates. If barrier nets were deployed between April 1 and October 31, according to data from the 2007 study, 36% of the impinged fish at Petersburg would have been excluded from the intake based on the assumption that barrier nets are 60% to 95% effective during the period they are deployed. The remainder of the year, fish would have been protected at the predicted modified traveling screen rate of 55%. Therefore, overall annual reduction would be estimated at between 57% and 70%. However, as written, the draft rule does not allow consideration of excluded fish toward the numeric IM reduction goals.

E Effectiveness

Barrier nets would not be effective at reducing E.

Capital Costs and Economic Feasibility

The capital costs associated with barrier nets are estimated to be approximately $780,000 for a 150 foot net at the Petersburg Station. This cost is based on installing the nets across the intake on pilings with a floating debris boom.

Barrier nets are also likely to require substantial operation and maintenance costs. The total costs will be dependent on the impacts of actual debris loading, biofouling, and icing. Therefore O&M costs are difficult to predict accurately. However, for the purposes of this assessment costs have been estimated at $100,000 annually, based on the assumption that the nets would be removed and reinstalled once each year to account for ice loading in the winter. In addition, it has been assumed the nets would be inspected and cleaned by divers on a monthly basis. Depending on actual conditions encountered, more or less frequent inspections and cleaning could be necessary. These costs are included in the O&M estimate.

Conclusions

While barrier nets could potentially be installed successfully at Petersburg, maintaining it would likely be very challenging and this measure would not provide credit towards the proposed Rule's impingement mortality limitations. AECOM understands that EPA is considering ways to credit measures that reduce impingement rates in the final rule. If the final rule does allow credit for measures such as barrier nets and retains a numeric performance standard for impingement that is applicable to Petersburg, barrier nets may warrant further consideration. However, as stated previously, the proposed rule does not provide credit for additional IM reduction technologies such as barrier nets. Therefore, this is not a recommended compliance options by AECOM at this time.

7.4 Ristroph Screens with Fine Mesh Panels (< 2 mm)

Overview

This alternative consists of replacing the existing traveling screens at the IPL facilities with Ristroph screens (as described in Section 4.1 above) and adding removable fine mesh panels with 1 mm openings to reduce E.

Harding Street Station's average intake flow over the past three years is less than 125 MGD and will only be reduced further with planned future unit retirements. Therefore, the proposed rule's requirements for assessing alternative to reduce entrainment do not apply to Harding Street. Petersburg does have an actual intake flow of greater than 125 MGD. Therefore, fine mesh panels were considered only for Petersburg.

The new screens would be identical to those considered in Section 4.1 with the addition of removable fine mesh panels. These fine mesh panels would likely be installed on a seasonal basis during periods of high entrainment and removed during periods when clogging or carryover is a concern. The highest E rates measured at the IPL stations during the 2008 E study occurred in summer months. During other times of the year, E rates were very low or zero. Therefore, it has been assumed that the fine mesh panels would be installed during the summer.

Technical Feasibility:

The feasibility of fine mesh panels on the Ristroph screens is dependent on the potential for clogging, carryover, and the added head loss associated with the fine mesh screens. Fine mesh screens would result in greater head loss across the screen and higher through screen velocity than standard mesh screens. This has potential to impact pump operations, and therefore would need to be assessed prior to installing fine mesh screens. In addition, with finer mesh screens there is more potential for the screens to become clogged with debris. If the screen wash system is not effective at removing this debris, there is potential carryover of the debris to the backside of the screen where it has potential to cause clogging or fouling of the condenser and other equipment. Clogging of the screens could build up to the extent that head loss across the screen would result in pump cavitation, or even the collapse of the screen. The potential for these factors to limit the application of fine mesh panels is difficult to predict. Therefore, desk top modeling, detailed engineering, and field pilot testing would be required to assess these factors.

IM Effectiveness

Fine mesh traveling screens are primarily utilized to reduce E; on their own they do not offer any known advantages for reducing IM of organisms that are impinged on standard mesh screens[4].

E Effectiveness

E is reduced with fine mesh screens due to physical exclusion of organisms that would otherwise be entrained through standard 3/8 inch mesh screens. As a result, organisms that would be entrained through standard screens may become impinged on fine mesh screens. The effectiveness of such a system at reducing E could be assessed in two ways: 1) based strictly on the exclusion of organisms from the cooling water or 2) based on the survival and return of the excluded organisms to the water body. EPA indicates that the latter approach is relevant in the preamble to the proposed Rule.

The implications of the two approaches to defining E performance are significant. If performance is based strictly on exclusion of organisms that would be entrained through standard screens, then simply installing a screen with a small enough mesh will achieve reductions in E. On the other hand, when survival of these organisms is considered then it is necessary to design a system to return the organisms in a viable condition to the water body. The smaller life stages that would be subjected to E through standard screens are likely to be more fragile than larger organisms; therefore, ensuring that a large fraction of these organisms survive following impingement is likely to be extremely difficult. Therefore consideration of survival reduces the calculated effectiveness of fine mesh screen panels.

Predicting the performance of fine mesh screens for reducing E is difficult. Very little data are available on the performance of fine mesh screens at reducing the entrainment of organisms, and even less are available on the survival of small organisms following impingement on fine mesh panels. Despite these difficulties a rough estimate of the performance of fine mesh screens was developed. It has been estimated that 1 mm wedgewire screens could exclude approximately 35% of the organisms

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[4] Note the preamble to the proposed rule does list “fine mesh traveling screens with fish return systems” as a technology to reduce impingement mortality. It is not clear why they list this technology in addition to modified traveling screens with a fish return as fine mesh panels have no accepted impact on the mortality of organisms that would have been impinged on standard mesh screens.

susceptible to entrainment. Exclusion by traveling screens is likely to be slightly lower than this; however, the 35% estimated exclusion reduction was used as the maximum likely effectiveness of fine mesh panels. The actual exclusion and survival effectiveness could be much less.

The estimate of exclusion effectiveness does not represent the portion of the organisms that would be returned to the water body in a viable condition. Smaller life stage organisms (that would normally be entrained) experience mortality when excluded by fine mesh panels. Accurately estimating the potential effectiveness of fine mesh panels at returning aquatic organisms alive to the source water is difficult. However, there is a small amount of literature on the survival of ichthyoplankton following impingement on fine mesh panels. Taft et al. (1981) performed laboratory evaluations of post-impingement survival on several species[5] of ichthyoplankton. They found that mortality rates were greatly affected by several factors, including:

- Through-screen velocities (e.g., for 8 minutes of impingement, post larval yellow perch had 40% mortality at 0.5 fps and 80% mortality at 2 fps);
- Duration of impingement (e.g., striped bass post larvae impinged for 2 minutes experience 3.8% mortality while those impinged for 16 minutes experience 37.3% mortality).
- Life-stage of the organism (e.g., 5.2 to 5.5 mm prolarvae of alewife experience 4.1% mortality while 6.6 to 14.7 mm post larvae experience 82.7% mortality at 0.5 fps through-screen velocity and 8 minutes of impingement).
- Species of organism (e.g., at 0.5 fps and 2 minutes of impingement, post larvae of striped bass experienced 3.8% mortality while those of yellow perch experienced 97.1%).

Similar conclusions were reached in laboratory pilot testing done for the Prairie Island Nuclear Plant using walleye, bluegill, and channel catfish (Stone and Webster, 1980).

Ecological Analysts (1977) evaluated the biological performance of 2.5 mm fine mesh panels with a 0.4 fps through-screen velocity at the Indian Point facility on the Hudson River. The focus of this investigation was striped bass larvae. The rates of post-impingement survival for 10 to 18 mm larvae were relatively high (68% initial survival, 47% 96-hr survival) and are generally consistent with the observations of Taft et al., (1981). It is important to note, however, that Taft *et al.* (1981) found that the smaller, prolarvae of striped bass experienced far lower rates of survival (i.e., 8% to 49% survival at 0.5 fps).

Kuhl and Mueller (1988) tested the biological performance of 0.5 mm fine mesh panels of several species by assessing initial, latent, and overall (i.e., initial * latent) survival rates over several years at the Prairie Island facility. These authors discriminated between different life-stages but, consistent with most of the papers cited here, did not assess the impingement or survival of eggs. Their results generally confirm the results of Taft *et al.,* (1981) and show highly variable survival rates of different taxa and life stages.

McLaren and Tuttle (2000) evaluated the survival of fish impinged on fine mesh panels at the Somerset Station on Lake Ontario over several years. The fine mesh panels had 1 mm slot size and, following wash off, organisms were segregated into "impinged" (i.e., those that do not pass a

[5] It should be noted that the ichthyoplankton species tested are ones which are robust enough to survive rearing in culture. Tafeet et al., (1981) evaluated striped bass, winter flounder, yellow perch, blue gill, walleye, channel catfish, and alewife.

9.5 mm screen) and "entrapped" (i.e., those that pass 9.5 mm but not 1 mm screens). Initial viability and 96-hr survival were evaluated for both populations. While screen-approach velocities were high (0.88 to 1.08 fps under normal lake stage and two- to three-times that under low stage), operation of the handling and return system was optimized over several years and survival generally improved. Most "entrapped" fish tested for survival were juveniles and small adults. Only in one case (post-yolk-sac larvae of rainbow smelt) was survival monitored for a larval life stage. Survival ranged from 0.9% to 100%.

These studies illustrate the survival factor is highly variable, depending on life stage, species, intake structure characteristics, and other factors and so is very difficult to predict.

Effectiveness of fine mesh panels is based on the exclusion of organisms the screens and the survival of those organisms following contact with the screens. Both of these factors are difficult to predict. The exclusion of organisms is based on in part on the size and life stage of organisms entrained. However, the relationship between these factors is not clearly understood. The studies illustrate that survival is highly variable, depending on life stage, species, intake structure characteristics, and other factors and so is very difficult to predict. Despite these challenges we have roughly predicted that fine mesh panels have the potential to exclude up to 35% of the organisms that would be entrained. However, we have estimated that only approximately 36% of these would survive exclusion and subsequent return to the water body. Therefore, if both exclusion and survival are considered, the total EM performance of this alternative is roughly estimated to be 13%.

Capital Costs and Economic Feasibility

The capital cost for removable fine mesh panels was estimated using parameters from the TDD (USEPA 2004) and the dimensions of the IPL facilities. The estimated capital cost for the screens would be approximately $550,000 for placement on the screens in all six bays in the Unit 1 and 2 CWIS at Petersburg Station. This cost assumes that these screens would be installed on Ristroph travelling screens that are designed to accommodate fine panels as add-ons. Fine mesh panels were not considered for Harding Street as Unit 7 is CCC.

Operation and maintenance costs associated removing, re-installing, and maintaining the fine mesh panels is estimated to cost an additional $140,000/yr over and above the maintenance costs associated with standard Ristroph screens. This cost assumes that the fine mesh screen panels would be installed and removed once per year to accommodate periods of high debris loading and is based on an assumed labor cost of $50/hr. If more frequent removal and replacement of the panels is required the costs would increase substantially. If major debris clogging or biofouling issues are encountered, other substantial costs could be encountered.

Conclusions

While fine mesh panels are potentially feasible, the total EM performance of this alternative is roughly estimated to be 13%. While this estimate is very uncertain, it suggests that this alternative may not be particularly effective at reducing EM. Despite this low performance estimate, this alternative may present the best alternative for reducing entrainment at a reasonable cost. If this alternative were to be considered, it would be important to conduct site-specific tests of clogging, carry over, and organisms exclusion and survival prior to implementing this alternative.

7.5 Closed Cycle Cooling

Closed Cycle cooling was considered for Petersburg Unit 2 alone (Case 2) and for both Units 1 and 2 (Case 3) (Case 1 being neither unit converting to closed cycle). Currently, Petersburg Generating Station operates Units 1 and 2 with once-through cooling, with a half cooling tower on Unit 2 that is utilized during summer months. Units 3 and 4 at Petersburg are closed cycle.

Retrofit of closed cycle cooling for Harding Street Station was not considered. Under the proposed 2015 operating conditions, Harding Street Station will operate only Unit 7 which is already closed cycle.

<u>Description:</u>

The existing cooling water systems at Petersburg Units 1 and 2 use river water pumped through a steam condenser and discharged back to the source water body. These systems are generally referred to as open cycle or once-through cooling system because the water simply passes through the condenser (no recirculation) where heat is transferred from the steam to the cooling water prior to discharge. Closed cycle systems recirculate the cooling water. Typically, the heated water from the condenser is cooled down in each cycle using evaporative cooling. This cooled water is then recirculated to the condenser to cool and condense the steam from the turbine. In the mechanical draft-cooling tower, fans are used to circulate air that flows against the heated water sprayed inside the tower. Cooled water is collected in the tower basin and returned to the condenser. Water must be introduced into the system at regular intervals to make up for losses due to blowdown and evaporation.

The makeup water flow for a mechanical draft-cooling tower is typically less than 5 percent of the flow required for once-through cooling. The makeup flow would be pumped to the circulating water system from the current intake structure. At Petersburg Station, blowdown is either discharged from the tower basins to the White River through separate NPDES permitted outfalls or to the on-site ash pond system to Lick Creek through a NPDES permitted outfall.

Water needs were determined from the facility water balance diagram and are presented in **Table 4.2.1**. Based on the facility water balance diagram, it is estimated that approximately 56,000 gpm (81 MGD), which includes estimates of makeup water for Units 1 and 2 cooling towers, would be needed to operate Petersburg Station with four units on closed cycle cooling. If only Unit 2, which has a one-half-size cooling tower (i.e., it is designed to dissipate one-half of the waste heat generated by Unit 2) is modified to full closed cycle cooling, Unit 1 circ pumps must provide sufficient flow to feed makeup water to cooling towers serving Units 2, 3, and 4 as well as other plant needs. Unit 1 circ pumps have DIF capacity of 112,000 gpm or 161 MGD which is more than sufficient to provide flow to the other three units' makeup water and other plant needs shown in **Table 4.2-1**.

<u>Technical Feasibility and Reliability:</u>

The technology proposed for this alternative is well known and has been implemented for similar power plants. Despite this, only a very small number of power plants using once-through cooling have retrofitted to cooling towers. This alternative requires substantial open space, consumes a substantial amount of electricity, and reduces the thermal efficiency of the system. In addition, the ability of the existing condensers to handle the higher pressures associated with the recirculating system is uncertain and could have a large effect on the costs for this alternative.

Significant site constraints and operational concerns at the Petersburg Generating Station impact the potential to install new cooling tower systems at the facility. Little space is available on site that would be conducive to installation and operation of cooling towers. Towers would have to be placed where drift would not impact existing switchyards and substation equipment. Underground piping from condensers to the cooling tower location would have to be installed under existing boilers and generating units, greatly disrupting plant operations. For cost estimating purposes for this study, AECOM has placed the proposed Unit 1 cooling tower on the northwest side of the site between the existing Units 3 and 4 cooling towers and the river as shown in **Figure 2**. This placement, as well as placement anywhere on the site, presents significant challenges and would involve significant disruption of plant facilities and operations. Despite this, it was used to represent a potential placement of the cooling towers for costing purposes. The cooling tower for Unit 2 was assumed to be an expansion of the existing half cooling tower that is located just east of Units 3 and 4 towers.

Estimated Costs:

The capital costs associated with retrofitting both Petersburg Unit 1 and 2 would be approximately $161MM. The capital costs for installing closed cycle cooling on Unit 2 are estimated to be $71MMThese capital costs are based on the following assumptions:

- A ΔT of 13°F was assumed for the CTs
- The cycles of concentration are 3.0
- Drift rate is 0.001%
- New cooling water pumps are installed with the retrofit to closed cycle cooling

Cooling towers also have significant operating and maintenance costs. These costs are associated with parasitic power consumption and water treatment costs. Each of these values was estimated for both cases and included in the annual O&M costs. In addition, there is likely to be a loss of turbine efficiency associated with the installation of the closed cycle cooling. In this case, we were not able to confirm turbine exhaust backpressure curves for the Petersburg facility prior to completing this report, therefore we utilized the EPA's TDD estimate of 1.0% efficiency loss for fossil fuel plants. Based on our experience the actual efficiency may be lower, therefore this represents a conservative value. Based on the turbine exhaust backpressure, we will adjust this factor in the final report.

For the case in which both units are converted to CCC, we estimated that the total O& M costs associated with closed cycle cooling are approximately $5.8MM annually. For the case in which only Unit 2 is converted to CCC, we estimate that the total O&M costs are approximately $2.7MM. These costs include routine maintenance of the cooling tower equipment, parasitic power loss and chemical water treatment costs. Annual parasitic power costs due to operation of cooling tower fans and loss of plant efficiency is estimated at approximately $0.8MM for the first case and $0.40MM for the second case. We assumed that the power costs are $0.04/kw-hr.

Finally, installation of cooling towers will require some unit downtime. We have estimated that the project duration of Case 3 would be approximately 15 months. We have assumed that the net downtime would be approximately 5% to 10% of this total project time, or approximately 1 month. Based on the assumption that the Petersburg facility would have been utilized at a 95% rate during this period and the lost revenue is $0.04/kw-hr, we have estimated that this downtime would cost approximately $12MM. Using a similar approach for Case 2, we have estimated that the project duration would be approximately 11 months and the downtime approximately one month. The downtime costs for Case 2 are estimated to be $6.3MM. These estimates represent the worst case, whereas if the plant cooling tower installation and associated down time were to occur during a regularly planned outage, these costs would have already been accounted for in the outage plans.

Capital cost estimate developed by AECOM were compared with costs developed using cost factors based on total cooling water flow presented in EPRI's 2011 Technical Report on Closed Cycle Cooling Retrofit Study. This comparison indicates that the costs for installing closed cycle cooling on both Units 1 and 2 are comparable to the cost derived from the costing factors that are applied to "more difficult" installation of cooling towers by EPRI 2011 (**Figure 3A**). Our estimated costs are likely high due to the significant distance between the condenser and the location of the cooling towers. This distance has a substantial impact on costs. The estimated costs for the installation of closed cycle cooling on Unit 2 only is somewhat less than that derived with the "difficult" cost factors from EPRI 2011 (**Figure 3B**). In combination, these comparisons support the capital cost estimates for the two cases considered.

Additional cost considerations and an assessment of the ratio of costs to benefits of closed cycle cooling have been presented in Section 4.5 of the Compliance Strategy Plan.

<u>Effectiveness:</u>

The mechanical draft cooling tower alternative reduces intake flow by typically 95% or more. It is assumed that it results in similar reductions in impingement and entrainment. This technology is considered Best Technology Available for entrainment reduction in the 316(b) rule. However, the rule requires closed cycle facilities to implement additional measures to achieve compliance with the IM requirements.

<u>Other Potential Adverse Effects:</u>

Closed cycle cooling systems result in other adverse environmental impacts that may offset the benefit of reduced impingement and entrainment. Operation of closed cycle cooling towers will increase energy consumption by the plant; increase in water effluent temperature, though decreasing volume; increase in air emissions (particulates due to cooling tower drift and overall emissions due to decreased plant efficiency); increase water consumption; increase noise levels; increase safety concerns; and increase the potential impacts to plant and therefore grid reliability.

The primary adverse effects for the mechanical draft cooling tower alternative are associated with increased water vapor content in the immediate area of the cooling towers. This will result in a visible plume for some periods and has the potential to result in fogging impacts. To reduce the potential for these effects, a plume abatement system would be employed. Because cooling tower drift cannot be eliminated completely, the tower would be located as far as possible from electrical equipment, off-site receptors, and sensitive vegetation. Space limitations may make it difficult to locate the cooling towers to minimize these effects. A cooling tower also imposes noise and aesthetic impacts. Another significant environmental effect is that the decrease in efficiency means that more fuel is burned per unit of electrical energy output. Therefore, a plant with cooling towers will have more emissions than a plant utilizing an open cycle system. The increase in emissions will be proportional to the decrease in plant efficiency. We have assumed a 1.0% loss in efficiency for the Petersburg facility based on EPA's TDD document; therefore, we have assumed a 1.0% increase in emissions from the plant.

<u>Overall Assessment of Alternative:</u>

EPA considers facilities that have closed cycle cooling to have Best Technology Available for entrainment mortality reduction. IPL is retiring its once-through cooling units Eagle Valley and Harding

Street Station Units 3-6 by the end of 2015. Therefore, these facilities will be compliant with entrainment requirements. Converting Petersburg Units 1 and 2 to closed cycle cooling would eventually bring Petersburg into compliance with BTA for entrainment. However, the benefit of achieving compliance must be balanced against the difficulties of fully installing cooling towers for Unit 1, very substantial capital and O&M costs, negative environmental impacts, and operational implications of closed cycle cooling. Therefore, compliance approaches other than closed cycle cooling should be pursued to the extent possible. AECOM's recommendations are provided in Section 5 of the Compliance Strategy Plan.

7.6 Measures to Reduce Intake Velocity

Description

Reducing intake velocity to below 0.5 fps is generally accepted to greatly reduce impingement rates. In addition, it has the benefit of allowing a facility to avoid the need to meet impingement mortality performance standards in the rule. As a result, facilities that choose to reduce their intake velocity have a defined path to complying with the rule's impingement mortality requirements.

Intake velocity can be reduced by reducing intake volume or by increasing the open area of the screens. Flow reductions can be achieved by installing closed cycle cooling, retiring units, operational measures, installing variable speed pumps, or by making other pump modifications. The primary way to increase screen open area is by expanding the intake structure and adding screen wells. It may also be possible to increase open area by installing dual flow screens.

Technical Feasibility and Reliability

At the Petersburg Generating Station under current once-through cooling conditions, intake velocity exceeds 0.5 fps. At current intake velocities, the size of the current intake structures would need to be more than tripled to achieve the desired reduction in velocity. Current intake velocities are 1.60 fps for Unit 1 and 1.32 fps for Unit 2. Therefore, expansion of the intake structures would likely be very costly and may not be feasible. If one or both of Unit 1 or 2 were converted to closed cycle cooling, the reduced cooling water needs could reduce velocity sufficiently so that additional modifications could achieve the 0.5 fps through screen velocity.

At Harding Street Station, current through-screen velocities exceed 0.5 fps at the two CWIS. Future operating conditions involve retirement of Units 3, 4, 5 and 6. Velocity reduction could be met with reduced pumping capacity and CWIS modification.

Modification of CWIS at Petersburg: A modification of the existing CWIS bays has been considered to reduce the through screen velocity below 0.5 fps if Unit 2 was converted to closed cycle cooling. This would be accomplished by creating an opening through the concrete walls separating the individual bays of the CWIS. The openings would be designed to promote equal flow through each of the screens feeding each active pump. In this way, the two Unit 1 pumps would see an increase in available area of three times, resulting in a reduction of velocity by one third to approximately 0.53 fps. In order to increase area sufficiently to reduce velocity the maximum extent possible at Petersburg, openings would be made in five concrete walls between the intake bays on the pump side of the traveling screens. Unit 2 make-up water would be drawn from the discharge canal where its existing cooling tower and the cooling towers for Units 3 and 4 currently draw their makeup water. This option is not considered feasible by Petersburg plant personnel and will not be considered further.

Reduced Intake Capacity at Harding Street: If Units 3, 4, 5 and 6 are retired at the Harding Street facility, the maximum design intake velocity could be reduced to below 0.5 fps by installation of lower capacity pumps and CWIS modification to increase screen area. It has been estimated that one 16,000 gpm pump would be sufficient to provide the necessary flow to Unit 7 for makeup water and other plant needs. Therefore, only one pump will operate at a time with the other pump designated as back up.

Currently, operation of one pump in each intake bay at current design rate of 24,750 gpm produces an intake velocity of 1.17 gpm. Reduction of pump capacity to 16,000 gpm would reduce design intake velocity in each bay to 0.76 fps. In order to further reduce velocity in each bay to less than 0.5 fps, the structure must be modified to increase screen area. This may be accomplished by creating an opening through the concrete wall separating adjacent bays of the CWIS, opening two bays to each pump. In this way, each of the two 16,000 gpm pumps (one active, one backup) would achieve through-screen velocity of 0.38 fps. Therefore, to achieve reduction of design intake velocity at the Harding Street Station, pump capacity must be reduced and CWIS must be modified. Replacing all four CWIS 5&6 pumps with 10,000 gallon pumps and operating two pumps at all time, would reduce intake velocity to 0.48 and eliminate the need to expand the CWIS. This option would require installation of modified traveling screens on all four intake bays which is approximately twice the cost of replacing only two traveling screens if only two pumps are replaced.

Reduce Intake Capacity at Petersburg Generating Station: If Unit 2 is converted to closed cycle, the reduced water needs of the plant present additional opportunities to reduce flow and velocity at the CWIS.

Replace Unit 1 circulating water pumps with ones of lower capacity: Unit 1 circ water pumps currently have DIF capacity of 112,000 gpm or 161 MGD which is more than sufficient to provide flow to the other three units' makeup water and other plant needs shown in **Table 4.2-1** in the Technical Memo. Under this scenario and with the existing CWIS, the intake velocity is estimated to be 1.6 fps. Replacing existing Unit 1 pumps with pumps from the Unit 2 bays could lower velocity in proportion to the difference in pump capacity. Unit 2 circ water pumps are rated at 46,250 gpm which is 83% of the existing Unit 1 pumps capacity. Therefore, replacing Unit 1 pumps with Unit 2 pumps, in conjunction with modification of the CWIS described above, would reduce design intake velocity by an additional 17%, reducing CWIS intake design velocity from 0.53 fps to approximately 0.44 fps. Reduced pump capacities could also eventually reduce plant actual intake flow to below the 125 MGD trigger for entrainment requirements.

Replace all CWIS pumps with lower capacity pumps: The existing pumps in all six bays of the existing Units 1 and 2 CWIS could be replaced with pumps of lower capacity to achieve <0.5 fps velocity and still be able to provide sufficient flow to the remainder of the plant. Current water needs of 81 MGD, based on the plant water balance diagram, and 0.5 fps velocity could be achieved with six 17,500 gpm pumps. This modification would require re-piping of the Unit 2 bay pumps to the piping for Unit 1 condensers. It is not clear how this would be accomplished. Further engineering investigation would need to be conducted to determine the feasibility of this option.

Variable Speed Pumps: Installation of variable speed pumps was investigated as a way to reduce intake flow and velocity at the Petersburg Generating Station. Existing circulating water pump controls would be replaced with variable speed pumps and variable speed drives added that could automatically adjust pump speed to draw just the amount of water required for plant needs. This could be also potentially be utilized to reduce the average intake flow over the three-year rolling average timeframe to attempt to drop below the 125 MGD trigger for entrainment requirements. This could also be used to decrease design velocity in combination with modification of the Petersburg Unit 1 CWIS described above by limiting the highest pumping rate to that which would reduce design intake velocity to below 0.5 fps.

Cost Considerations

Modification of CWIS at Petersburg: The facility modifications required to expand Petersburg CWIS to reduce intake velocity to near 0.5 by opening the walls between intake bays, in conjunction with conversion of Unit 2 to full CCC, is estimated to be approximately $300,000 (cost of modification to intake bays only). AECOM investigated the engineering requirements of opening the side walls between bays through review of existing design drawings and developed cost estimates from that study. However, detailed engineering studies would need to be conducted to fully develop this option. The cost to modify the Harding Street Station CWIS to increase screen area for each reduced capacity pump is estimated to be approximately $100,000.

These costs are comparable to the costs of conducting the IM studies required under the rule which are expected to be approximately $250,000. However, there is no guarantee that the results of the impingement study would meet the performance standards for IM survivability and the station may be forced to implement technological solutions anyway. Reduction of velocity to below 0.5 fps eliminates the requirement to meet those standards.

Reduced Intake Capacity at Harding Street: The cost to replace two pumps at Harding Street with 16,000 gpm pumps is estimated to be $1,000,000, based on estimates provided by Harding Street plant personnel.

Reduce Intake Capacity at Petersburg Generating Station:

Replace Unit 1 circulating water pumps with ones of lower capacity: The cost of replacing Unit 1 circulating water pumps with lower capacity pumps from Unit 2 bays at Petersburg Generating Station is has not been estimated at this time. This reduction in pump run capacity is expected to result in lower O&M costs due to reduction in electrical use, similar to that expected through use of variable speed pumps described below for an expected O&M cost reduction of $44K per year.

Replace all CWIS pumps with lower capacity pumps: The cost of replacing all six CWIS pumps with lower capacity pumps and modifying the piping from Unit 2 bays to Unit 1 condensers has been estimated to be $3.4MM. This cost assumes replacement of six existing circulating water pumps with six pumps of 17,500 gpm capacity and re-piping Unit 2 circulating water lines to provide flow to the Unit 1 condensers. The cost of detailed engineering study to finalize plans for this modification is included in the total capital cost estimate. The estimated change in O&M costs through installation of lower capacity pumps is negligible from the total O&M costs included in the conversion of Unit 2 to full CCC.

Variable Speed Pumps: Installation of variable speed pumps to replace the two Unit 1 circ pumps at the Petersburg Generating Station is estimated to be $3.0MM, assuming that Unit 2 is converted to full closed cycle cooling. This cost includes installation of two variable speed drives, new pumps, and new motors. Operation and maintenance costs associated with variable speed pumps would actually decrease from existing circ pump O&M costs due to the reduced electrical consumption. The reduction in O&M cost is expected to be $44,000 per year. This cost includes only the reduction in electrical use associated with lower capacity pump motors. Other O&M costs for maintenance of pumps are assumed to be the same as existing.

IM Effectiveness

Velocities of less than 0.5 fps are believed to reduce impingement rates by 90% or greater (Preamble to draft Rule 76 FR 22202). Furthermore, as discussed above, this measure eliminates the need to demonstrate compliance with impingement mortality numeric limitations in the draft rule.

E Effectiveness

While a reduction in only velocity would not contribute to a reduction in entrainment, the reduction of flow associated with variable speed or lower capacity pumps would provide a proportional reduction in entrainment. Increasing the flow area without a corresponding decrease in flow is not known to be effective at reducing entrainment rates. Therefore, the facility will need to ensure there is a decrease in flow for entrainment BTA purposes.

Conclusions

At Petersburg, there is not sufficient screen space available to get either the actual or design intake velocity below 0.5 fps under the projected operations without expanding the intake structures. If Unit 2 is converted to fully closed cycle, there is some potential that reducing the pumping rate and modifying the intake so that the remaining circulating water pumps draw water through all six intake bays would reduce the value to near 0.5 fps. Replacement of existing Unit 1 circulating pumps with ones of lower capacity or installation of variable speed pumps could reduce velocity further to below 0.5 fps. These options should only be considered if Unit 2 is converted to full closed cycle cooling.

Based on costs, engineering feasibility and input from Petersburg plant personnel, AECOM recommends replacement of existing circulating water pumps in all six bays with pumps of lesser capacity to reduce velocity to below 0.5 fps in the long run. AECOM's recommendations are presented in more detail in **Section 5.**

At Harding Street, with the retirement of Units 3 through 6, velocity reduction would be accomplished through installation of lower capacity pumps and modification of the CWIS

7.7 Potential Retrofit Costs

A final summary of compliance options investigated and recommendations is provided in the 316(b) Compliance Strategy Plan.

8.0 Summary

This 316(b) Technical Memorandum presents the existing and planned conditions at Indianapolis Power & Light's (IPL) Petersburg Station, Harding Street Station, and Eagle Valley Station, and examines the compliance options for these plants with the proposed Section 316(b) Rule published in April 2011 in consideration of recently announced plans to close certain units at two of the IPL stations. This document summarizes the current and proposed plant conditions, describes the requirements of the draft rule as written, presents the applicability of the rule to the plants under the proposed 2015 operating conditions, outlines permit application requirements, and provides a screening review of technologies that may be considered for compliance. The information presented in this Technical Memorandum will be used to develop a 316(b) Compliance Plan that will delve more deeply into the permitting requirements and potential compliance options at the three IPL generating stations.

IPL has proposed retiring the Eagle Valley Station and retiring Units 3, 4, 5, and 6 at the Harding Street Station. These actions will leave Petersburg Units 1, 2, 3, and 4 and Harding Street Unit 7 in operation after approximately 2015. .

The 316(b) draft rule requires submittal of facility information within six months of finalization of the rule which is expected in July 2012. It is unclear how the state permitting authority will enforce these requirements for facilities with active NPDES permits, such as the IPL stations. The agency could modify existing permits, require separate submittals outside the permitting timeframe or put off the submittal requirements until the next permit cycle. It is also unclear how the agency will handle the permit application requirements in lieu of the soon to be announced closure of several generating units and the entire Eagle Valley station. Comments have been submitted to EPA to help clarify this and other questions regarding the draft rule.

Previous submittals of facility information made in 2008 were reviewed for completeness with regard to the draft rule. It was determined that the previously submitted reports will have to be modified moderately to reflect proposed facility information expected in 2015. Additional reports and studies will be required based on the expected operating conditions at each of the facilities. The previously prepared 2008 reports will, however, serve as a resource for the development of those additional documents.

It is expected that Eagle Valley Station will either be relieved of the need to submit the reports, or will be required to submit minimal information which could be accomplished with the previous reports and minimal additional information. Harding Street Station is expected to be required to submit documents pertaining to impingement mortality, but with only one unit remaining active, and that unit being operated with closed cycle cooling, Harding Street would not be required to submit any documents or complete monitoring surveys for entrainment mortality. However, in order to maintain operational options, Harding Street Station may choose to complete the permit application requirements and conduct the impingement monitoring study until future plans are solidified. Petersburg Station is expected to be required to submit documents and conduct studies for Impingement and Entrainment mortality under current operating conditions.

Technologies were investigated for their potential to reduce impingement and entrainment mortality at the remaining stations/units to meet the goals of the 316(b) draft rule. Many of the technologies were determined to be infeasible or ineffective. The technologies that have some potential to be applied to the Harding Street and Petersburg Facility and their costs are described in **Appendix B** of this Technical Memorandum. Since the Eagle Valley facility is planned for closure, an evaluation of alternatives was not conducted.

A final summary of compliance options investigated and recommendations is provided in the 316(b) Compliance Strategy Plan.

Appendix A

Site Inspection Summaries

On August 16 and 17, 2011, AECOM's engineer visited the three facilities to inspect the CWIS for the purpose of potential upgrades to the systems that could be considered to achieve compliance with the draft 316(b) rule. The following notes summarize the results of those visits.

Eagle Valley

- CWIS expansion would be hampered by concrete bulkhead to the west, but there are no buildings in that area to prevent it. This could be considered to increase CWIS screen face area to reduce through-screen velocity, if other less costly compliance alternatives are not available.
- Existing traveling screens are standard models. Would be replaced to upgrade to Ristroph system. Units 1-4 traveling screens are indoors and 5 and 6 are outdoors. The screens are automated and are not rotated manually. All 6 Units traveling screens are capable of continuous operation. The screens are rotated one full rotation per shift unless river conditions require that the screens are run more often or continuous.
- Fish return trough would need to be extended several hundred yards to the west to direct it away from the intake structure and return more gently to the river. Current system passes through 8- or 12-inch pipe and empties onto concrete bulkhead well above the river level. Collection basket had significant amount of debris, but no fish were observed.
- The main stream of the river is well off shore from the CWISs. A low head dam downstream of the CWISs provides constant head for the CWISs during low river flow conditions.
- The width and main stream location of the river would appear to be sufficient to allow placement of a barrier net or fixed fine mesh screen barrier parallel to the river flow to cut down on through-screen velocity and maybe provide entrainment barrier. Potential problems include keeping the screens or nets free of accumulated debris to maintain low through screen velocity, protecting against damage from floating debris, protecting against the force of flood stage flow, and constructing to ensure full barrier for all river flood stages. Dredging is occasionally needed to maintain depth the area in front of the CWISs.
- Very tight spacing between bar racks and traveling screens would make manual velocity measurement difficult and likely precludes placement of fixed fine mesh panels there.
- Helper cooling tower withdraws makeup water from discharge canal. CT make up water withdrawn from the discharge canal is not considered a withdrawal from a Water of the US (same classification as the CCRS makeup water at Petersburg and HS).

Harding Street

- Two separate CWISs on river bank accessible by foot bridges. Space is available to expand U1-4 structure, but U 1&2 forebays are not being used and could be reactivated to provide twice the width for U 3&4 and cut velocity in half without new structure. Would need to break through walls between forebays. Traveling screens have been removed from Units 1 and 2 fore bays.
- Traveling screens are old and would be replaced for conversion to Ristroph. Existing screens are operated as needed, but not very often. Existing debris wash return discharges directly in front of intakes. No flow was observed in Units 3 and 4 at the time of the visit. Debris was observed in the collection basket of Units 5 and 6, but no fish were observed. Tops of Units 5 and 6 traveling screens are insulated and outdoors. Units 3 and 4 traveling screens are inside a building.

- A new fish return trough to direct away from the intakes would be challenging to construct and maintain. CWISs are tucked in behind a sand bar that is dredged every few years. The sand bar and a spit of land that extends into the river to the south form an impoundment in front of the CWIS. The new trough would have to run over the water out beyond spit, approximately 400 feet to reach the river outside of the impoundment so fish would not be subject to immediate re-uptake in the CWIS. This return trough would be subject to damage from flooding and would be susceptible to freezing. The new trough could run along river bank to the south to the river side of the spit upstream of discharge canal, but would be several hundred yards long and would be susceptible to freezing. Warmed water would likely need to be added to the trough flow to prevent freezing in winter, but could stress fish.
- Plant personnel reported that the Corps of Engineers, when asked in the past, would not allow dredging of the spit which blocks river flow through the area in front of the CWIS. Opening this path for flow would allow return of fish directly into the river greatly reducing the distance needed for the fish return trough.
- Placement of a barrier net or fixed fine mesh panel structure in the river is a possibility, based on width of the river and the main stream being far off shore, but sedimentation will be a continuous problem, considering the current sand bar dredging program.
- Cooling water from Units 3 and 4, and Units 5 and 6 discharges along with other facility wastewater streams and storm water into an underground “Junction Box”, from where discharge flows by gravity through pipes to the discharge canal. Very little flow was observed in the discharge canal during visit. CT for Unit 7 makeup water is drawn from the junction box as is ash sluice water.
- In summer, Units 5 and 6 divert water from the junction box for use in once through helper cooling towers to help meet effluent thermal limits. This along with CT 7 makeup and ash sluice water withdrawal could theoretically cause a negative flow to the discharge canal unless other flow is provided. Units 3 and 4 circ pumps are operated to maintain positive flow to the junction box and the outfall.
- Unit 7 CT makeup draws approximately 10,000 gpm and ash sluice water draws approximately 5,000 gpm. Units 3 and 4 need to provide more flow than this to keep positive flow to the outfall or else the discharge will become an intake. Another solution would be to allow some of the flow from Units 5 and 6 to pass to the junction box while diverting the rest to the helper CTs, if this would allow sufficient cooling to still meet the effluent thermal limits. This may not be possible if the valves that divert flow to the CTs cannot be throttled, but can only be operated fully open or fully closed.

Petersburg

- Space is available to expand CWIS to the north, if needed. Space available is about the same width as current CWIS building.
- A large pipe provides warmed post-condenser circ water to the front of the CWIS in winter to prevent freezing of the intake stream. This pipe is mounted above the normal river level directly in front of the CWIS.
- Existing traveling screens are in good shape, but would likely need to be replaced to upgrade to Ristroph. Currently the screens are rotated in response to differential pressure.
- Separate fish return trough would have to be extended downstream away from intake and upstream of discharge canal. Space is available to the south of the CWIS along the shore to

accommodate this. Current debris wash trough discharges into the discharge canal where temperatures may result in stress to the fish.

- Collection basket contained debris, but no fish were observed. Rate of flow through collection basket was very high, and may result in stress to the fish. Low pressure wash of Ristroph would have to be separated from debris wash which is consistent with the requirements of the proposed rule.
- River is sufficiently wide to allow placement of off-shore barrier net or fine mesh fixed panels. Debris collection will be an issue as will river flood stages. River in this area is highly susceptible to flooding.
- Low head dam downstream of CWIS provides constant water level during low river flow conditions.
- Unit 2 cooling tower is ½ size, but could potentially be expanded to the same size as 3 and 4 and potentially serve as CCC for Unit 2 and maybe also Unit 1. Space is available to expand the towers to the north and primary piping to the CT appears to be the same size as those to 3 and 4. It appears that pipe sizes of condensate lines in and out, makeup line, and blowdown line to the existing cooling tower could allow expansion to accommodate the full flow from Unit 2.
- Constructing piping from CWIS to CT and to Unit 1 condensers would cause significant disruption of the plant equipment and operations. Potential CT location is not readily apparent, but would have to be far away from substation (to avoid vapor deposition) and other plant equipment.
- Units 3 and 4 CT makeup water intake draws from Units 1 and 2 discharge canal. Intake structure consists of fixed screens behind bar racks. Water is drawn from an impoundment formed by low dam below the outfall pipes from Units 1 and 2 and the intake structure of Units 3 and 4. The dam provides fixed water level during low river flow essentially cutting the impoundment off from the river. River flooding would easily rise up over the dam, however.

Appendix B

Technology Reviews

Potential Technologies

This appendix outlines the approach used for assessing alternatives for reducing IM and E at the IPL facilities. First, technical feasibility was assessed to understand what site-specific physical limitations may impact the application of a given technology. Next, capital and operational costs were estimated. This was coupled with an analysis of likely IM and E reduction effectiveness. All these factors were considered to identify those that have potential for application at the IPL facilities.

This screening assessment considered the available “fish deterrence, screening, and intake avoidance technologies, and more effective rotating screen equipment for the CWIS” that have some potential to be installed at IPL’s facilities. Fish deterrence and intake avoidance technologies are those that lead organisms to avoid entering the CWIS. Screening technologies include those that screen organisms from the water withdrawn by the CWIS. While flow reduction measures (e.g. closed-cycle cooling and variable speed pumps) are not considered to be fish deterrent, screening, or intake avoidance technologies, these measures have potential to reduce IM&E and so are also reviewed in this assessment.

The following 10 technologies represent the available fish deterrence, screening, and intake avoidance technologies for this assessment.

- Deterrents (acoustic barriers and strobe lights)
- Louvers
- Barrier Nets
- Aquatic Filter Barriers (e.g., Gunderboom®)
- Porous Dikes
- 1 mm Wedgewire Screens
- Offshore Intakes with Velocity Caps
- Angled Traveling Screens
- Ristroph Modified Traveling Screens (described in the body of the report)
- Fine Mesh Traveling Screens

Additionally, closed cycle cooling, fine mesh panels, and flow reduction through variable speed pumps were also considered. Closed cycle cooling is described in the body of the report.

Feasibility of Potential Technologies

Feasibility was assessed based on the plant cooling water intake flow rates, source water body characteristics, potential regulatory constraints, and any site-specific factors that could limit implementation, maintenance, or reliability. The potential for other adverse environmental effects was also considered where appropriate. Based on these considerations, potential constraints on installing or operating the technologies were considered and documented in the following sections.

Deterrents

Overview

Deterrents are technologies designed to repel aquatic organisms from the area in front of cooling water intake structures, and thereby reduce impingement of organisms. Typically deterrents consist of strobe lights or sound transducers, or both. There are a number of different potential combinations of deterrent technologies that might be applied to the IPL facilities. These include installing sound transducers or strobe lights independently, or in combination.

For the purposes of this report, consideration was given to an array of both sound transducers and strobe lights deployed directly in front of the existing intake at one of the IPL facilities to deter fish from entering the screen house. For cost estimating purposes it was assumed that a separate rack holding the transducers and lights would be constructed and installed on the outside of sheet piling wall upstream of the screen house. Each rack would support strobe light heads and sound transducers. In total, it was estimated that approximately 10 strobe lights and 6 sound transducers would be required to cover the area of the intake. Alternative arrangements are possible.

Technical Feasibility

There are no significant barriers to installing and operating strobes and acoustic transducers at the IPL facilities. One potential operational challenge would be addressing fouling of the lights and transducers. This issue may result in substantial operational costs; however, it could likely be overcome.

IM Effectiveness

Attempts to assess and quantify the effectiveness of deterrent systems at reducing IM resulted in conflicting conclusions. At some locations these devices have been relatively effective at reducing IM. In other locations and/or for some species deterrents have not been demonstrated to be effective.

A study at a plant on the Mobile River in Alabama found no evidence of a hybrid light and sound deterrent being effective at reducing impingement (Garrett 2006). Measured impingement rates were not significantly affected and, using acoustic monitoring of the area around the CWIS, the number of fish present in the vicinity of the deterrent system did not decrease when the deterrent system was active. In fact, during some tests rates of impingement and populations of fish in the fore bay of the CWIS increased when the deterrent system was operated.

Other studies have shown light, sound, or hybrid systems to be effective. In field testing, Patrick et al. (2006) provided two separate measures of potential IM reduction at the Lambton Generating Station using a hybrid acoustic system. Based on hydro-acoustic monitoring of fisheries near the CWIS, they reported a 50% reduction in fish densities in front of the screens when the hybrid system was active. Based on randomized testing of the system relative to no controls, IM rates for gizzard shad decreased by approximately 70%. It should be noted, however, that IM events at Lambton are episodic and that a longer record may be necessary to ensure that substantial IM events do not occur with the hybrid system active. The acoustic system, without the strobe deterrent, was not as effective as the hybrid system at this location. In a separate study, Saksen and Hoser (2006) demonstrated approximately a 75% reduction in IM for blueback herring using high frequency sound deterrence at the Danskammer Point Generating Station located on the Hudson River in New York.

Based on these studies, it is clear that a range of IM performance has been observed at test facilities. However, the studies outlined above do suggest that this technology (a hybrid system) has the potential to reduce the impingement of gizzard shad, potentially by as much as 70%. This species likely represents between approximately 45% and 65% of organisms susceptible to impingement at the IPL facilities. Emerald shiner may also be effectively deterred from the intake by deterrents.

Based on these considerations, it was estimated that the performance of a similar hybrid system at the IPL CWISs at deterring fish may be around 50-60%. However, the low through-screen intake velocity at the Harding Street facility allows many organisms to swim away from the screen. Therefore, the net effectiveness of this alternative may be substantially less. Furthermore, without site specific testing, estimates of effectiveness of this alternative are highly uncertain. Pilot testing and detailed engineering studies would need to be conducted to test and further estimate the effectiveness of any technological solution.

Entrainment Effectiveness

This alternative relies on organisms avoiding the area near the intake. Organisms that are entrained generally have very limited or no mobility. Therefore, this alternative is not known to be effective for reducing E.

Capital Costs and Economic Feasibility

Capital costs for the hybrid deterrent system are based on vendor quotes for the prices of the sound and light generators and RS Means for the structure to support the devices. The cost of installing this alternative at the IPL facilities was estimated to be approximately $600K per facility or $1.8M for all three.

Costs associated with cleaning and periodically replacing the strobes and transducers are estimated to be approximately $65K annually for each facility. Substantial biofouling problems may result in higher O&M costs.

Since the effectiveness of this alternative is highly variable and site-specific, significant pilot testing would be required. It was assumed that such testing would cost approximately $200K at one plant.

Conclusions

There is some potential that IM could be reduced by deterrents. There is considerable uncertainty in the performance of deterrents, and the anticipated capital and O&M costs associated with the implementation of deterrents could be substantial. While technically feasible, the site-specific performance of this technology would require significant investigation prior to committing to installation. This technology is not recommended for further review.

Louvers

Overview

Louvers consist of an array of angled vertical slats designed to direct fish away from a cooling water intake and into a fish diversion. Generally, a louver array consists of a line of vertical slats placed across an intake canal at an angle to the direction of flow. The line of louvers creates an area of localized turbulence that fish can detect and avoid. While water flows through the angled slats, fish are diverted to the downstream end of the line of louvers to a fish diversion canal or other return system. This technology requires substantial bypass flows; therefore, most installations have been at hydroelectric facilities where hydraulic gradients in the river allow for a bypass flow without the installation of fish pumps. At hydroelectric installations, bypass flows are typically a minimum of 5-10% of the total flow. There is limited information on the effectiveness of this technology at cooling water intake structures in other types of facilities. In this evaluation, the installation of louvers was coupled with installation of a sheet pile wall that would direct the fish downstream away from the intake structure. This was more feasible at Eagle Valle and Petersburg where open river is available just downstream of the CWIS, than at Harding Street where sedimentation has created an impoundment in front of the CWIS which would lead to re-capture of fish placed in that area.

Technical Feasibility

Installing an effective array of louvers in front of the cooling water intake structure of the IPL facilities would be technically feasible only if it proves to be technically feasible to install fish return pumps which both generate sufficient bypass flow, and return fish without significant rates of mortality. There would be challenges associated with keeping the louvers free of debris and biofouling organisms; this would likely require major effort during periods of high debris loading. The presence of debris and possible biofouling could potentially: reduce the effectiveness of louvers as a deterrent, impede water flow into the CWIS, and result in damage to the louvers themselves. Ice formation could also reduce the effectiveness of louvers and/or damage them.

Another challenge would be creating sufficient bypass flow. In contrast to hydroelectric plants, the required bypass flow would have to be supplied by fish pumps withdrawing water from the downstream end of the louver array. These pumps would likely result in some mortality to the bypassed fish, particularly for those species that are sensitive to handling. In addition, the required bypass flows could be substantial resulting in high power requirements and O&M costs.

IM Effectiveness

The effectiveness of this alternative is dependent on the rate at which it diverts organisms from the intake and the survival of those diverted organisms following their passage through fish bypass pumps. There is very limited data on the effectiveness of louvers with fish bypass return pumps. The San Onofre Nuclear Generating Station, located on the Pacific coast of southern California, has the only system with available efficacy data that is known to exist. At this plant the louvers have been arrayed upstream of the circulating water pumps at an angle to the intake flow. Diverted fish are returned to the water by a fish pump system. Studies at San Onofre Nuclear Generating Station show that the overall effectiveness of the louver system and fish bypass system varied significantly between units and study years from 36% to 90% reduction in impingement (Bailey 2005). The effectiveness of such a system would be reduced by any mortality through the fish bypass system. The limited data on survival of fish through such a pump indicates the survival is species-dependent and highly variable. In some cases survival approaches 100% and in others none of the fish survive handling in the fish pump (Bailey 2005).

A louver system would subject the diverted organisms to passage through a fish pump with potential for additional mortality. Therefore, it is not clear that this alternative would have any net effect at reducing IM at the IPL facilities.

E Effectiveness

These diversion devices are not known to be effective in substantially deterring fish eggs and larvae, or other planktonic organisms. Therefore, they would be ineffective at reducing E.

Capital Costs and Economic Feasibility

It was estimated that the costs of installing a simple louver array in front of the existing intake would cost approximately $125K per site for the louvers alone. In addition, fish pumps, a fish return flume and additional sheet piling structures would be required to create an intake channel that would house the louvers. In total the estimated costs would likely exceed $700K per site, with more cost at Harding Street where a more extensive fish return system would be needed to provide a path out of the existing impoundment. Total cost for the three plants is estimated at $2.5M.

Net O&M costs for this installation would be related to replacing any louvers damaged by debris and the costs associated with clearing the debris and biofouling from them periodically. Also there would be O&M costs associated with the fish pump of sufficient size to achieve the required bypass flows. These costs could be substantial, but are not estimated here.

Conclusions

There have been very limited applications of louvers in cooling water intake structures. The majority of louver applications are at facilities and settings very different from the IPL facilities (e.g., at riverine hydroelectric power facilities). As a result, the effectiveness of louvers at deterring fish and the optimal design for such an array of louvers is highly uncertain. In particular, it is not clear that louvers would be effective at reducing IM relative to an intake with a low through-screen velocity. The low intake velocity of the Eagle Valley and Harding Street facilities' CWIS already allows many organisms to swim away from the intake. Therefore, it is not clear that this alternative would reduce IM at the IPL at those facilities. Furthermore, organisms that are deterred from the screens would travel through a fish pump with some associated mortality.

Louvers are likely to accumulate debris and biofouling organisms (e.g., zebra or quagga mussels). This debris would require regular cleaning of the louvers, and potentially damage the louvers thereby reducing their effectiveness. While potentially commercially available, this alternative was not considered further due to the lack of commercial practicability (based on limited information on their effectiveness and the likely O&M challenges)

Aquatic Filter Barriers

Overview

Aquatic filter barriers (AFBs, commonly referred to as Gunderboom™ systems) consist of a fine mesh fabric curtain through which the water is drawn. In the process, planktonic organisms are filtered from the water and therefore not entrained. The low water velocity through the fabric also reduces or eliminates impingement, by allowing organisms to swim away or be swept away by ambient currents. In addition, AFBs commonly include an air burst technology that can be implemented periodically to force accumulated materials off of the curtain and back into the water column. Based on the IPL facilities' design intake flows (EV: 233,000 gpm; HS: 165,000 gpm; Pete: 297,000 gpm) and an assumed average water depth of 10 feet, fabric curtain barriers of approximately 1,899 feet at Eagle Valley, 2,006 feet at Harding Street, and 2,240 feet at Petersburg would be required to achieve the recommended flow rate through the fabric of 3 to 5 gpm/feet^2 (USEPA 2004).

Technical Feasibility

Installing an AFB to accommodate the flows necessary to support once-through cooling has been determined to be infeasible for the following reasons:

- The extensive length of the AFB required in order to achieve the recommended flow rate (at least 1,899 feet) would require closing off over a quarter mile of river bank.
- Substantial biofouling of the fabric would be expected and would potentially lead to clogging and induced stresses on the fabric. In particular, zebra and quagga mussels would have a potential to severely impact the feasibility of this technology. In addition, the barrier would likely be susceptible to clogging with *Cladophora*. Given the lack of ambient velocity in the river, it is not clear that an air burst cleaning system would be effective are reducing this clogging.

IM Effectiveness

The very low through-fabric velocity associated with an AFB is likely to nearly eliminate the impingement of organisms that would otherwise be impinged on standard mesh screens[6]. However, this effectiveness is predicated on the ability to maintain the integrity of the barrier. At other installations, this integrity has not been consistently maintained and overtopping of the barrier and gaps between the bottom and the curtain have occurred regularly (EPRI 1999). Therefore, actual performance is likely to be reduced considerably from that theoretically achievable with a flawless installation.

E Effectiveness

The very small opening size in the fabric has the potential to exclude nearly all eggs and larvae and substantially reduce E. However, the concerns about maintaining the integrity of the AFB (described above) are likely to significantly reduce this effectiveness in real world installations. Furthermore, any non-motile (or minimally motile) organisms would likely be impinged upon the AFB. Once impinged, the fate of these organisms would be uncertain. There is potential that a predator population would become established on the filter barrier and feed on the impinged organisms. Therefore, it is not possible to determine how much this alternative would reduce mortality associated with E. In fact, if a large fraction of the eggs and larvae that are impinged are subjected to mortality, this alternative may actually result in higher mortality for these size fraction organisms than if they had passed through the cooling water system[7].

Capital Costs and Economic Feasibility

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[6] For the purposes of this document we have considered the impingement and mortality of organisms that would be entrained through standard 3/8 inch screens as E effectiveness; we recognize that other paradigms are possible.

[7] A number of studies have demonstrated that a high proportion of entrained organisms survive entrainment in cooling water systems. In many cases, the survival of entrained organisms has been reported to be greater than 50% and in some cases greater than 90% (Mayhew et al 2000).

Estimation of the capital costs associated with an aquatic filter barrier of sufficient length would be an average of approximately $3.0 MM per site. O&M costs are likely to be substantial given the length of the barrier and its potential for biofouling. These costs would likely include repeated cleanings and replacements of portions of the barrier. However, since this alternative is judged to be infeasible, O&M costs have not been quantified.

Conclusions

Installing this alternative at the IPL facilities would not be feasible. If it were feasible, biofouling and debris loading would likely make maintaining the integrity of the barrier very challenging and expensive.

Porous Dikes

Overview

Porous dikes, also known as leaky dams or leaky dikes are structures constructed of stones that allow water to pass through them and into the cooling water intake structure. To accommodate the flows required at the IPL facilities, an approximately 800 feet long porous dike would be required. Given the limited space in front of the intakes, and the expected ecological impacts of placing such a large amount of fill in the river, it is not recommended that a dam of this length could be placed in the river.

Technical Feasibility

There are numerous issues that would likely make installing and maintaining an effective porous dike at the IPL facilities infeasible. The primary obstacle to installing a porous dike is the lack of sufficient area to accommodate the required length of dike. This would make designing an effective porous dike very difficult. In addition, maintaining such a structure would likely be extremely challenging and potentially impossible. The openings in a porous dike would be susceptible to clogging by debris and biofouling (particularly by zebra and quagga mussels). It is not clear that there would be any way to clean the dike if it became clogged. Finally, it is likely that permitting this technology would be challenging due to the impacts on the source water body.

IM Effectiveness

If properly constructed and maintained, a porous dike would have some potential to reduce IM. However, the magnitude of this reduction is uncertain, as there is not sufficient data in the literature to quantify the effectiveness of this alternative.

E Effectiveness

Porous dikes are not expected to be effective for reducing E of eggs and larvae. To accommodate sizeable flows, the openings in the dike would be larger than most of these organisms. In fact there is some potential for them to increase E if organisms use the dike or its immediate area as spawning or feeding habitat.

Capital Costs and Economic Feasibility

A porous dike of appropriate size for the IPL facilities would cost a minimum of $500K. However, as described above there is not sufficient space to accommodate such a structure and it is not clear it would be possible to maintain it.

Conclusions

The construction and maintenance of a porous dike at the IPL facilities would likely be infeasible. In addition, this is a relatively unproven technology, with few installations. As a result, this technology is not a viable alternative for reducing IM or E at the IPL facilities.

Wedgewire Screens

Overview

Wedgewire screens are cylindrical screens constructed of wire that has a triangular cross section such that the surface of the screen is smooth while the screen openings widen inwards. Wedgewire screens are designed to reduce entrainment by physical exclusion of eggs and larvae and are also designed to minimize impingement due to their typically low intake velocity and by taking advantage of the “sweeping velocity” of the ambient currents in the source water body. A typical installation would include an array of tee-shaped cylindrical screens in the source water body. The cylindrical screen design has been used for several power plant applications and other intake structures.

The following table presents the number of 42-inch diameter wedgewire screens with 1 mm slot size[8] that would be required to achieve the necessary flow at each IPL facility. Each screen would be approximately 12 feet long and have a capacity of 5,000 gpm. The screens could be arrayed in parallel in front of the CWIS on the river bottom in water of sufficient depth. The screens would be constructed of a copper alloy or a similar material to minimize the potential for biofouling by zebra and quagga mussels and other organisms. With the implementation of wedgewire screens, the need for the traveling screens inside the intake house would be eliminated (however, EPA has established a requirement to install Ristroph screens at every CWIS with existing traveling screens regardless).

Facility	Intake Flow	Required number of 12-foot Wedgewire Screens
Eagle Valley	233,00 gpm	19
Harding Street	165,000 gpm	21
Petersburg	297,000 gpm	23

[8] Note that wedgewire screens with larger slot sizes (e.g. 9 mm) are available. However, they are not effective at reducing E and as described below would not be effective at reducing IM. Therefore, this analysis focused on finer mesh wedgewire screens. Many of the issues raised in this analysis would apply to coarser mesh screens.

Airburst cleaning systems are typically used to keep the screens clean. The airburst system consists of a compressor and receiving tank and air lines to the wedgewire screens. While the conceptual design includes this cleaning system, there may be difficulties with designing such a system to be effective. The ability of an airburst to system to thoroughly clean the screens of organisms (biofouling) is not clearly established. This has potential to be a serious concern at the IPL facilities due to the presence invasive species. In addition, the effectiveness of the cleaning system may be limited by lack of a sweeping current in the intake canal. Any debris removed by the airburst would remain in the vicinity and potentially be re-impinged on the intake. Therefore, further investigation would be required to ensure that this cleaning alternative would be effective in this location.

Technical Feasibility

There are a number of factors that could impact the feasibility of installing and maintaining wedgewire screens at the IPL facilities. These concerns include the following:

- River depth and sedimentation. Bathymetric surveys have been conducted in front of the CWIS at each facility. Water depth varies from a minimum 5 to 10 feet in the river, heavily dependent on river flow rates. If the water level in the river drops significantly, the screen would extend above the surface and potentially entrain air, resulting in an increased intake velocity and potentially reducing the volume of water withdrawn. While this factor could likely be addressed by dredging out a deeper area within the river, this would add considerable capital and O&M costs. Anecdotal evidence suggests that the river carries a significant sediment load that could cause scouring around the screens or deposition of sediments on the screens. The area in front of the CWIS at Harding Street, Petersburg, and Eagle Valley are routinely dredged every three to five years.
- Debris and cleaning of the screens. An airburst cleaning system relies on an ambient velocity to sweep any debris removed from the screen away from the screen so that it is not re-impinged. The only potentially feasible location of the wedgewire screens is within the canal. However, there is no ambient current within the intake canal; therefore the airburst cleaning system may not be effective. In addition, it is not clear whether the airburst system would be able to cope with loads of plant matter, *Cladophora*, frazil ice and other debris that may clog the screens. Therefore, regular cleaning by divers may be necessary.
- Permitting. The permitting required for the construction and installation of wedgewire screens may be challenging. Placement of such structure will require permitting efforts under Sections 10 and 404 of the Clean Water Act, as well as review by IDEM under the Water Quality Certification Program and Antidegradation Requirements.
- Navigation hazard. Installation of wedgewire screens in the middle of the river could pose a significant hazard to pleasure craft traffic during low river flow conditions.

While it is possible that the concerns outlined in this section are surmountable, this study concludes extensive investigation would be required prior to committing to a full scale installation of wedgewire screens.

IM Effectiveness

There is a general consensus that wedgewire screens are effective at reducing IM when installed in an environment with an adequate sweeping velocity. When installed in appropriate conditions, they can reduce IM by 90% or more. In fact, when installed in a river with sufficient sweeping velocity, they were a pre-approved technology under the remanded Phase II 316(b) rule. Their effectiveness is primarily attributable to their low through-screen velocity ($\leq$0.5 fps) which allows fish with adequate mobility to avoid impingement. Achieving high reductions is also dependent on ambient sweeping current which may remove organisms that are impinged on the screens (EPRI 1999). A minimum ambient sweeping current velocity of 1 fps is recommended.

However, it is unknown what the survival rate of impinged organisms is following cleaning by an airburst cleaning system. In addition, it is important to note that their performance in a location without an ambient sweeping velocity, yet to be determined at the IPL plants, is uncertain.

This alternative would effectively replace the existing intakes and their effectiveness, or lack thereof at reducing IM.

E Effectiveness

The performance of wedgewire screens at reducing E is based on their ability to exclude organisms from the intake water. Most historical studies evaluating performance of wedgewire screens have addressed only exclusion and have not considered survival of larvae and juveniles that would have been entrained through standard mesh screens but are excluded on the finer meshed wedgewire screens. Similarly, in this evaluation only E performance based on exclusion was considered. If survival of these impinged organisms is considered, the total performance will be reduced, perhaps substantially.

Previous studies have found highly variable E performance for wedgewire screens (EPRI 2005). Exclusion of organisms from the wedgewire screens is based on both physical exclusion (due to the size of the slot opening relative to the dimensions of the organisms) and exclusion attributable to organism behavior and hydrodynamics. Given the lack of motility of most organisms subject to E, ambient sweeping velocities are also important for the effectiveness of this technology. The effectiveness of wedgewire screens at reducing E is generally higher with higher sweeping velocities (EPRI 2005). Therefore, all performance estimates are uncertain without site-specific testing.

Based on species-specific E effectiveness rates on 1 mm wedgewire screens, it was estimated that approximately 35% of the entrained fraction could be excluded by 1 mm slot size wedgewire screens. This estimate is based on wedgewire screens in environments with appropriate sweeping velocity. Accordingly, the actual performance at this site could be substantially lower. In addition, there is potential that some of the excluded organisms will experience mortality following impingement on the wedgewire screens.

Capital Costs and Economic Feasibility

The capital costs for the fine mesh wedgewire screens are based on EPA estimates from the TDD and conceptual design guidelines from Johnson Screens. The estimated costs likely represent the minimum costs; actual costs could be much higher. It was estimated that the capital costs of this option would be approximately $1.8 MM per facility.

Conclusions

If wedgewire screens could be engineered and installed at the IPL plants, this alternative would be likely be effective at reducing IM substantially relative to the existing traveling screen condition, which currently achieves no reduction in IM. The wedgewire screen alternative would likely have moderate effectiveness at reducing E, heavily dependent ambient sweeping velocity. This factor may also lead to operational challenges related to debris clogging and biofouling. In addition, the large swings in river level that are periodically experienced could result in the screens being exposed above the water; thereby potentially reducing the amount of water that can be withdrawn. Low river levels would also cause the wedgewire screens to pose a significant hazard to navigation of pleasure craft. If wedgewire screens were considered further, significant pilot testing would be required to evaluate the feasibility and effectiveness of this alternative. Due to the compounding effects of the potential drawbacks of this technology (navigation hazard, shallow river depth, sedimentation, scouring, biofouling, and unpredictable effectiveness), this technology is not recommended for further review.

Offshore Intakes with Velocity Caps

A velocity cap is a cover placed on a vertical inlet of an offshore intake structure. The cover results in a horizontal flow to the intake, and may reduce impingement compared to an intake with vertical flow because fish tend to avoid rapid changes in horizontal flow. Intake velocities of 0.5 to 1.5 feet/s are common. These structures are typically placed on intake structures that are located offshore.

An offshore intake with a velocity cap would be subject to the same restrictions due to navigation hazard and river level as offshore wedgewire screens, with even less likelihood of effectiveness. Therefore, this technology does not warrant further study.

Angled Traveling Screens

<u>Overview</u>

Angled and inclined screens consist of standard or Ristroph modified traveling screens set at an angle to the incoming flow. The angle of the screen is designed to cause the fish to move toward the downstream end of the screen, where bypass fish pumps capture and return them to the water body. This results in diversion of fish that would otherwise be impinged on the screens. This has potential to reduce the mortality of organisms that encounter the CWIS. This alternative has been implemented at a limited number of facilities.

Installation of angled traveling screens at the IPL facilities would require complete reconstruction of the intake bays and screen house. The intake bays would need to be reconstructed so that the screens were angled relative to the intake flow and to eliminate obstructions that could hinder a fish moving downstream along the screen faces. At the downstream end of the screen array a fish pump would be required to provide a bypass flow and return the diverted organisms to the water body. This configuration would increase the dimension of the screen house perpendicular to the front of the screen house substantially.

<u>Technical Feasibility</u>

Installing angled screens would require complete reconstruction of the intake bays and screen houses. While this is technically feasible it would be very expensive and interrupt facility operations.

<u>IM Effectiveness</u>

The effectiveness of angled or inclined screens at diverting the organisms is highly variable depending on the species (USEPA 2004). Some studies have suggested that high rates (up to 100%) of diversion can be achieved (Taft 1978). However, the survival of diverted organisms after they travel through a fish pump is not documented. It is possible that the mortality would be similar or greater than the mortality of organisms following impingement on a traveling screen particularly a screen designed to minimize organisms' mortality (i.e. Ristroph modified screens). As a result, it is not possible to quantitatively estimate the performance of angled screens at the IPL facilities relative to the existing screens. It is not clear that the performance of this alternative would be higher than standard Ristroph modified traveling screens which would be much less costly.

E Effectiveness

This alternative would not be effective at reducing E.

Capital Costs and Economic Feasibility

Installing angled screens at the IPL facilities would be estimated to cost a minimum of $7MM. This cost is primarily driven by the costs of reconstructing the intake structure. Since relatively few angled screens have been retrofitted to existing cooling water intake structures, these costs have considerable uncertainty and could be substantially higher.

Conclusions

This alternative is not known to be more effective than the existing intake or less costly Ristroph traveling screens. Therefore, angled screens are not considered further.

Dry Cooling Towers

Overview

Dry cooling systems virtually eliminate the need for cooling water withdrawals. Unlike wet cooling systems, in dry cooling systems, waste heat is transferred completely through convection and radiation, rather than evaporation. The system is completely closed to the atmosphere and there is no contact between the outside air and the steam or the resulting condensate. Due to the heavy reliance of dry cooling on ambient air temperatures and the lower efficiency of heat transfer through convection and radiation, dry cooling towers are much larger and therefore more expensive than wet cooling towers for a given cooling load. Dry cooling towers have been built in areas where limited water supplies exist for either once-through cooling or wet cooling make-up water, such as the arid southwestern U.S. The volume of makeup water is extremely low—a dry cooling system typically reduces intake flows by 98–99 percent over a comparable once-through cooling system.

Capital Costs and Economic Feasibility

The construction and capital costs for dry cooling towers have been reported as five to 10 times as expensive as wet cooling towers, and the parasitic load for dry cooling is higher than for wet cooling. The preliminary cost estimate for installation of dry cooling towers at Petersburg Station for Units 1 and 2 was $424MM.

Conclusions

Considering the cost and impracticality of installing dry cooling towers at a facility with ample supplies of water, dry cooling towers were not considered further for the IPL facilities.

Summary

Many of the ten alternatives considered were determined not be viable alternatives. This is because they were either infeasible, had uncertain performance, and/or were unlikely to substantially reduce IM or E. The bases for these conclusions are summarized below:

- Deterrents: While deterrents have the potential to be feasible to install and operate, their effectiveness is highly uncertain. In some instances deterrents have been highly effective. In others they have been associated with increased rates of impingement. Site specific testing would be required to determine actual effectiveness. Given the highly variable nature of impingement rates, documenting the effectiveness of this alternative would be challenging. This alternative is not effective at reducing E.
- Louvers: Louvers have rarely been installed at cooling water intake structures. As a result there is very little data on their effectiveness and the appropriate design for this application is unclear. There is no evidence demonstrating that this alternative would be more effective than the existing intake at reducing IM. In addition, louvers would require diverted organisms to pass through a fish pump resulting in some unknown associated mortality.
- Aquatic Filter Barriers: To accommodate the flows required by the IPL facilities, aquatic filter barriers of approximately 1,899 feet at Eagle Valley, 2,006 feet at Harding Street, and 2,240 feet at Petersburg would be necessary. There is not sufficient space for barriers of this length in front of the intakes. Therefore, this alternative is not feasible for the IPL facilities.
- Porous Dikes: A porous dike of length of approximately 879 feet at Harding Street 1,237 at Eagle Valley, and 1,577 at Petersburg would likely be required to accommodate the flows at each of the IPL facilities. Given the limited space in the vicinity of the intakes, it is unlikely a dike of this size could be installed. Furthermore, such a structure would likely be susceptible to clogging. It is not clear that there is an effective means to clean such a structure. Therefore, this alternative would not be feasible at IPL and is not considered further. If it were feasible, it is not clear how effective it would be at reducing IM or E.
- 1 mm wedgewire screens: The lack of sweeping velocity, river level fluctuations, risks to navigation, and permitting requirements have potential to make wedgewire screens infeasible. Significant study would be required before installing this alternative. Given the high costs, potential barriers to feasibility, and likely ineffectiveness at substantially reducing existing IM, this alternative was not considered further.
- Offshore Intake with velocity Cap: Due to the shallowness of the river and risks posed to navigation in the area installing offshore intakes would be infeasible. Therefore, this alternative was not considered further.
- Angled Traveling Screens: This alternative requires complete reconstruction of the intake structure, a bypass flow, and the use of a fish pump. The resulting costs would be very high. Travel through the fish pump subjects organisms to injury and an unknown mortality rate. This alternative is not known to be more effective than the much less costly Ristroph traveling screens. Therefore, it was not considered further.
- Dry Cooling Towers: Extremely expensive and not generally utilized in areas with ample water supplies.

The alternatives that were chosen for further review, Ristroph screens, barrier nets, fine mesh panel overlays, methods to reduce intake velocity including variable speed pumps, and Closed Cycle cooling, are described in the main body of this document and in the 316(b) Compliance Strategy Plan. They are expected to be feasible to install and maintain at the IPL facilities.

Appendix C

[redacted]

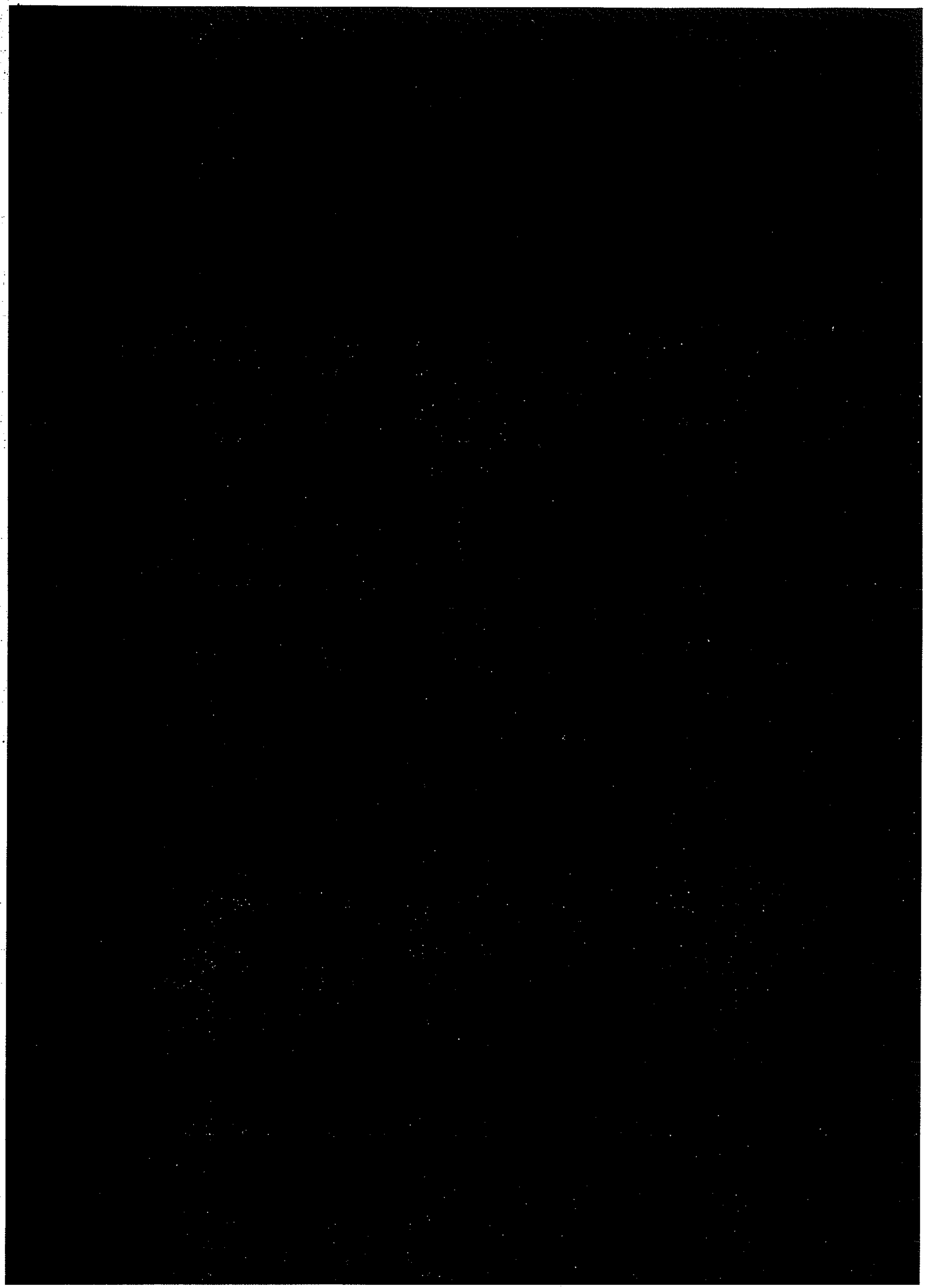
[redacted]

[redacted]

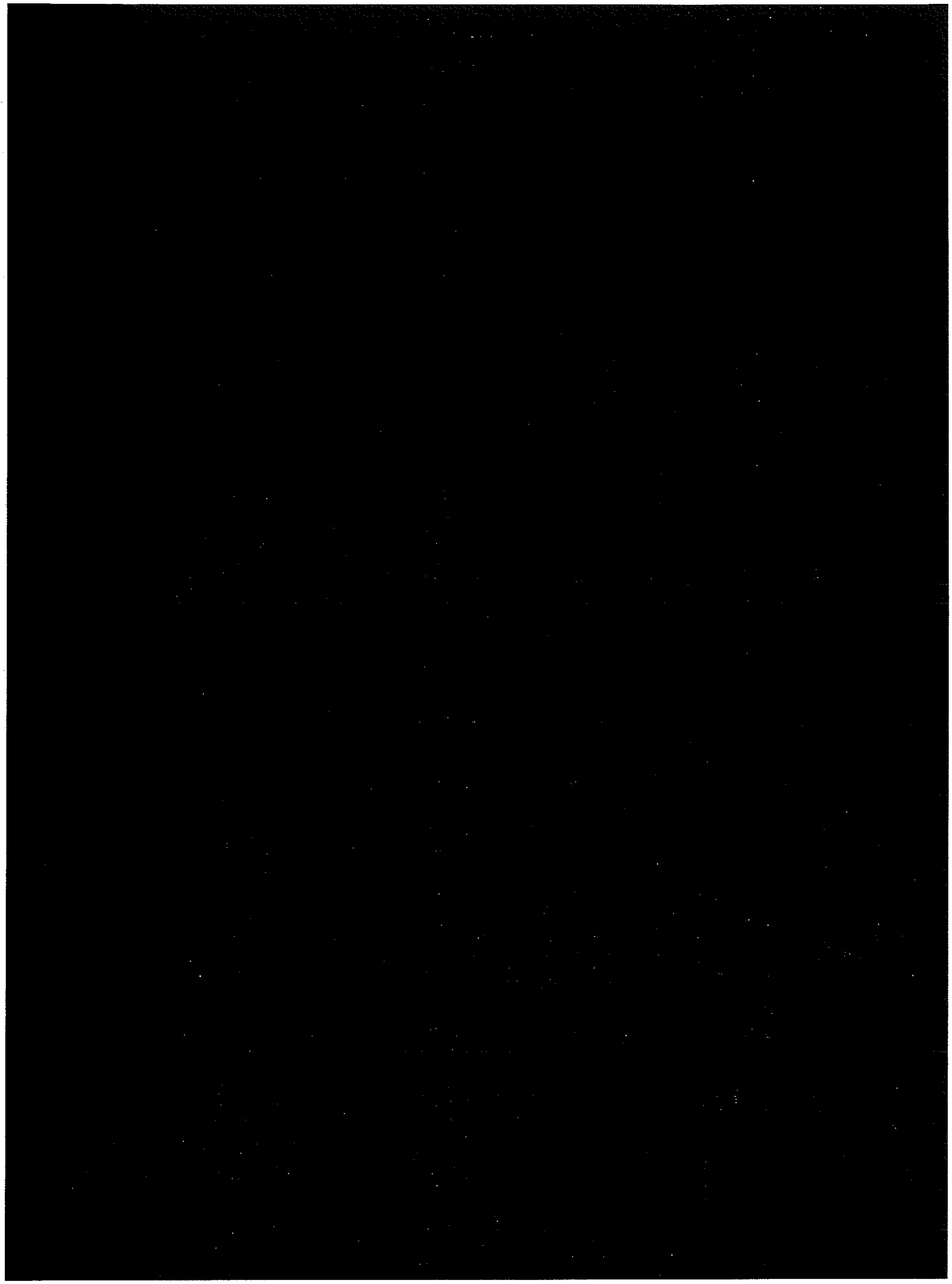
[redacted]

00050182

AECOM



00050183



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AECOM

[redacted]

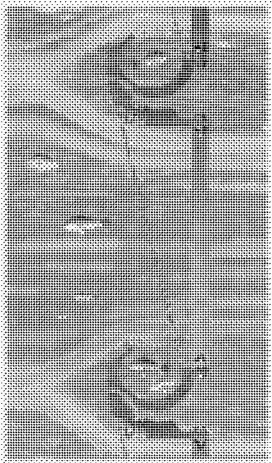
Appendix D

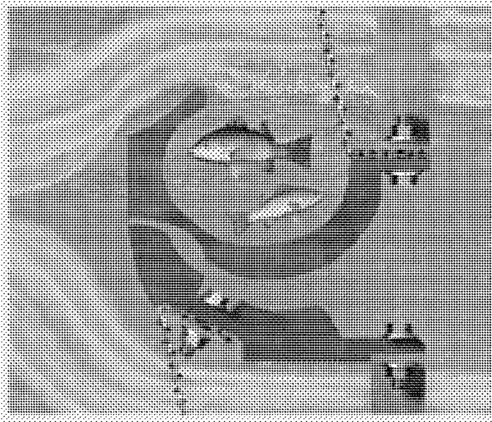
Modified Ristroph Screens

The following slides are part of a presentation by Siemens, a manufacturer of Ristroph modified traveling screen systems, to present an example of the look and operation of the systems.

SIEMENS

Modified Ristroph Screen





CLEAN WATER ACT: Section 316(b) of the Clean Water Act requires the location, design, construction and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact (AEI)

Page 2 Date Author filename.ppt **Water Technologies**

SIEMENS

Evolution of Design

Siemens has been designing, testing and improving fish protection systems since the late 1950's; long before the current regulations were conceived.

1958 – In conjunction with Dr. Joseph D. Ristroph,
Rex Chain Belt Company developed the capture and release fish handling method known as the "Ristroph Design" and was granted a patent for a "Fish Saving Apparatus for Traveling Water Screens."

1973 - Development of "Ristroph Modified" Fish Basket with die-formed metal lip by Dr. Ian Fletcher and Royce ® Traveling Water Screen Co (acquired by USFilter in 1988)

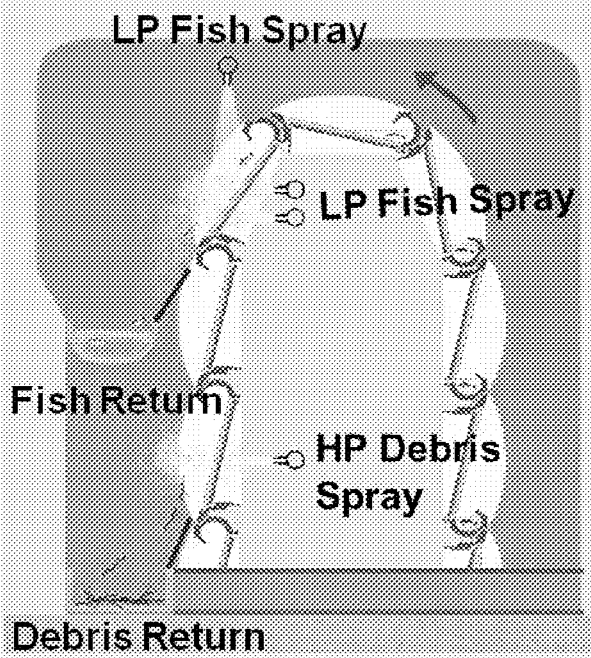
1993 – In conjunction with Dr. Fletcher, USFilter developed the Improved system known as the "Modified Ristroph/Fletcher Non-Metallic Fish Design Basket".

Page 3 Date Author filename.ppt Water Technologies

SIEMENS

Modified Ristroph Screens are a "Capture and Release" Design

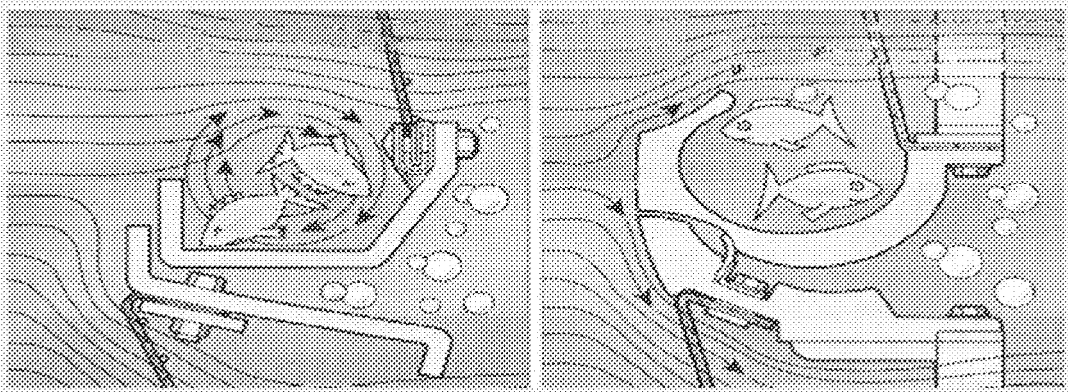
- These systems capture fish in a fish pan or bucket, elevate the fish to the surface.
- Assisted by low pressure sprays, the fish are discharged by gravity into the return trough prior to removing the debris from the surface of the screen cloth.
- The fish are returned to the body of water via a trough or sluice.



Page 4 Date Author filename.ppt Water Technologies

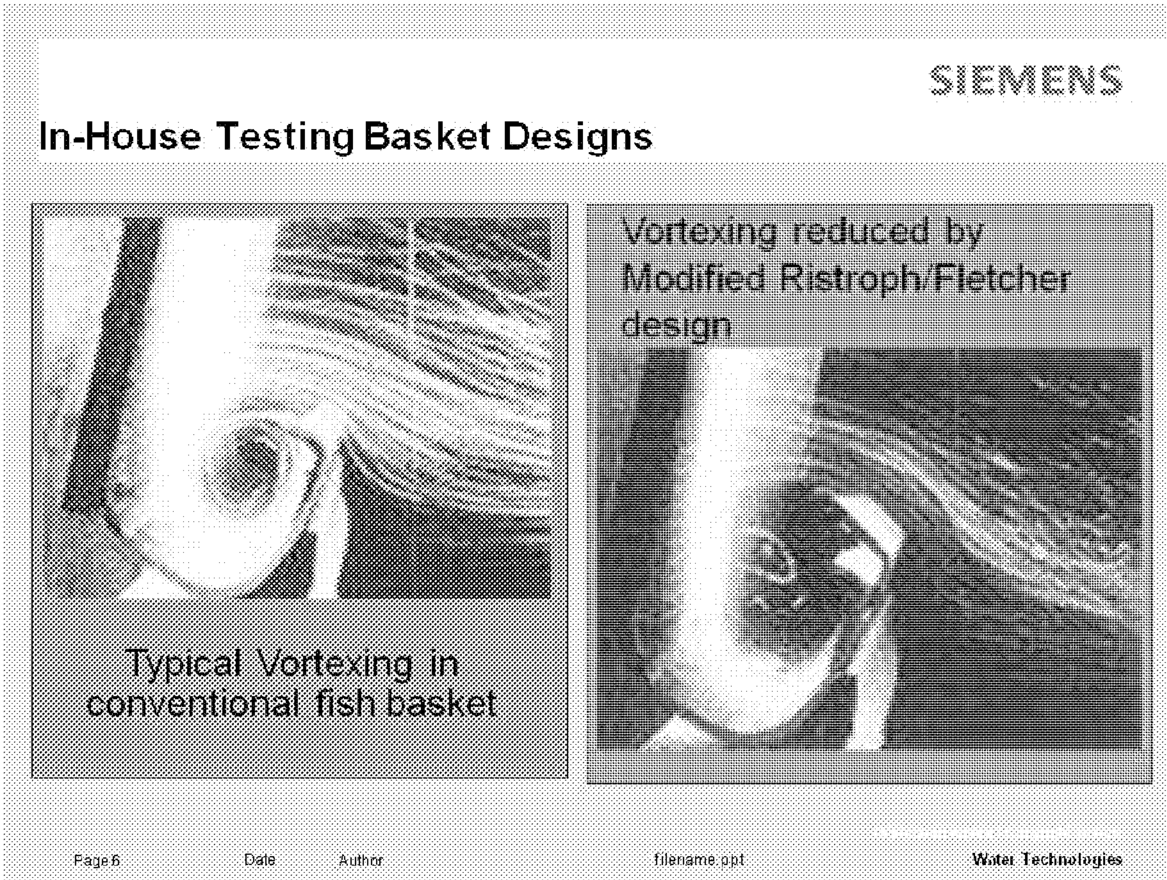
SIEMENS

Modified Ristroph/Fletcher Fish Baskets



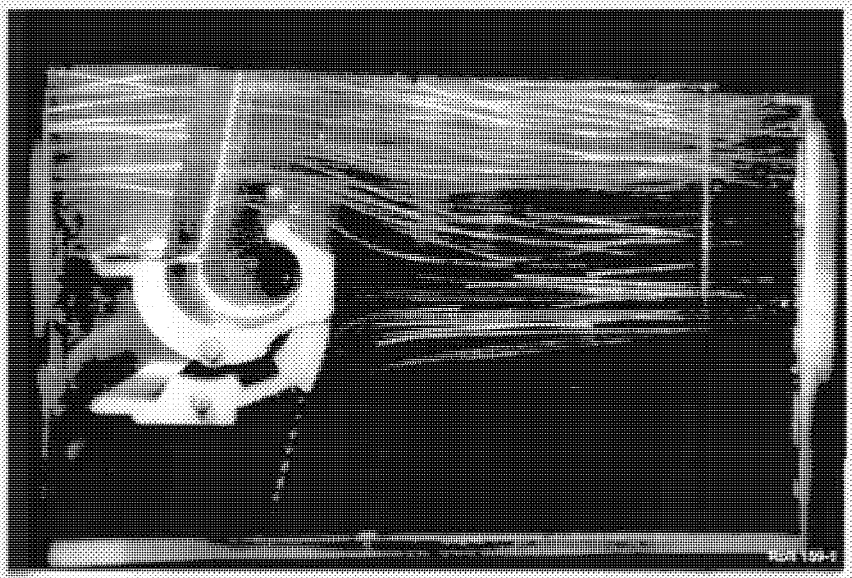
- Designed to increase fish survival rates
- Virtually eliminates turbulent vortexing within the fish conveyance zone.
- Fish are in safe environment that minimizes descaling and injuries.

Page 5 Date Author filename.ppt Water Technologies


SIEMENS
In-House Testing Basket Designs
Typical Vortexing in conventional fish basket
Vortexing reduced by Modified Ristroph/Fletcher design
Page 6
Date
Author
filename.ppt
Water Technologies

SIEMENS

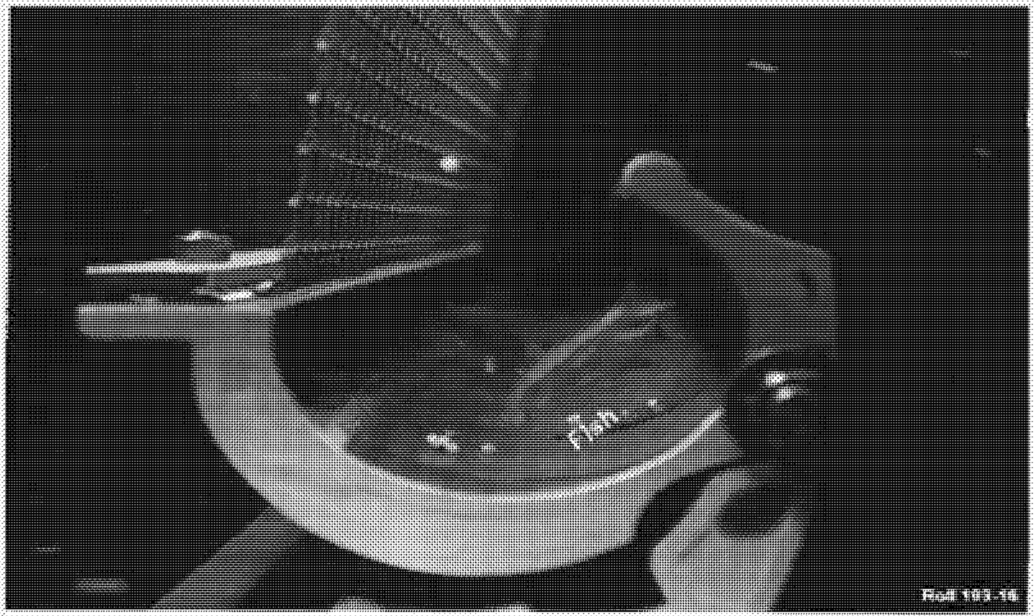
Flume Testing – Flow Modeling



Page 7 Date Author filename.ppt Water Technologies

SIEMENS

Flume Testing – Flow Modeling



Page 8 Date Author filename.ppt **Water Technologies**

SIEMENS

Modified Ristroph/Fletcher Fish Baskets

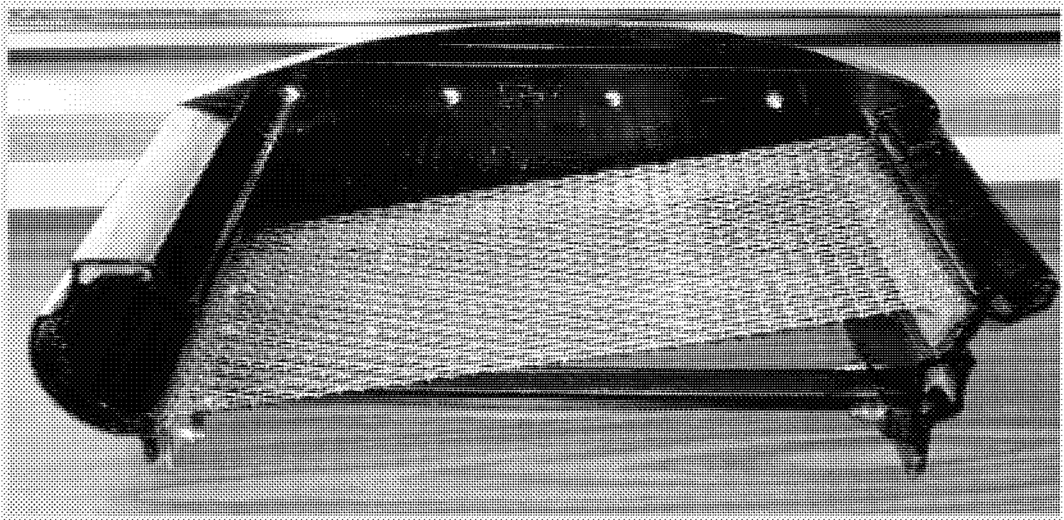
The Non-Metallic basket frame offers dramatically superior performance over conventional designs :

- Lower headloss
- Greater lifting capacity
- Better corrosion resistance – No painted needed
- Less than half the weight of steel or stainless steel
- Less wear and tear on mechanical parts – continuous travel

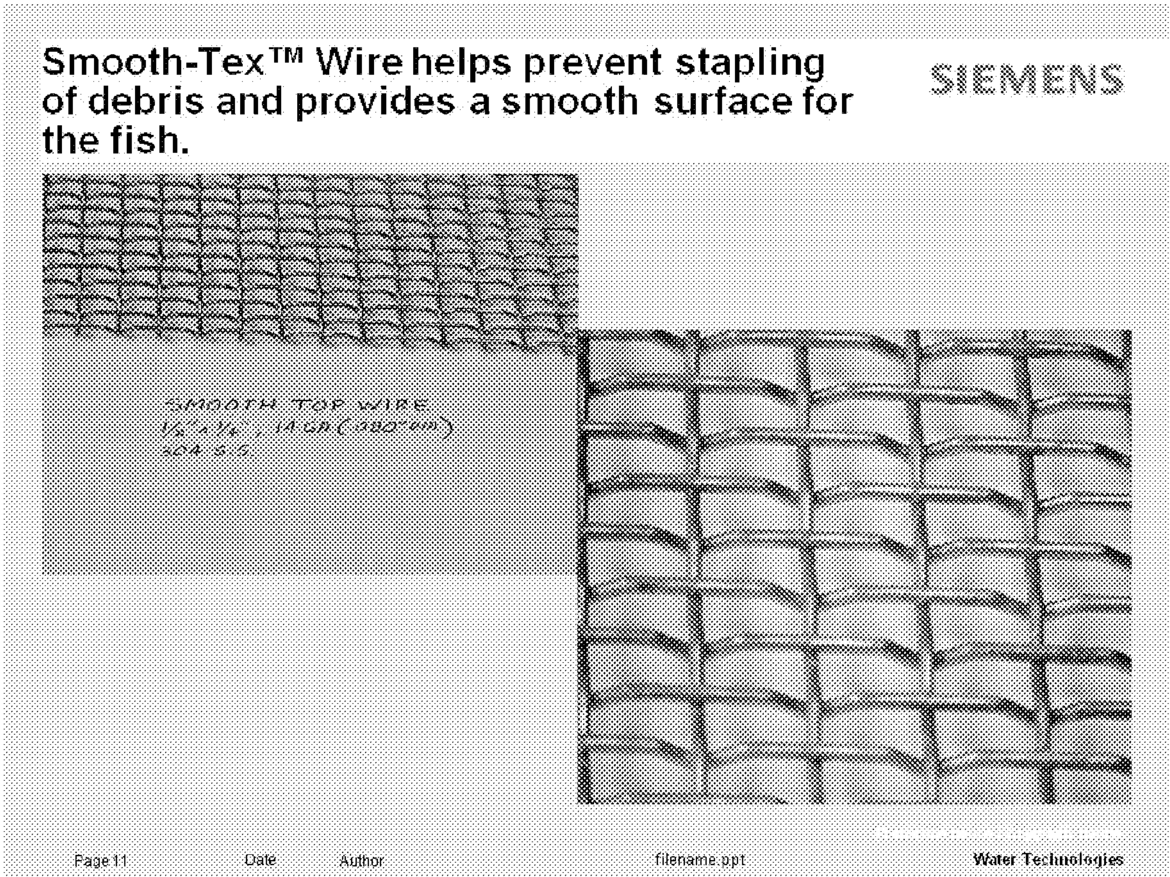
Page 9 Date Author filename.ppt Water Technologies

SIEMENS

Non-Metallic Basket



Page 10 Date Author filename.ppt Water Technologies


Smooth-Tex™ Wire helps prevent stapling of debris and provides a smooth surface for the fish.
SIEMENS
SMOOTH TOP WIRE
Page 11
Date
Author
filename.ppt
Water Technologies

Data Request 1-23. For each of the Big Five Units, identify and produce any analysis comparing the cost of continued operation of the unit with retiring and replacing the unit's energy and capacity with a combination of any of the following energy resources:

a. DSM

b. Market purchases

c. Power purchase agreements

d. Existing natural gas combined cycle or combustion turbine capacity

e. New natural gas combined cycle or combustion turbine capacity

f. Conversion of natural gas combustion turbines to natural gas combined cycle units

g. Combined heat and power

h. Wind

i. Solar

j. Geothermal

k. Any combination or permutation of the above resources

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection: IPL objects to CAC/SC Request 1-23 on the grounds and to the extent it solicits information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. IPL further objects to Request 1-23 on the separate and independent grounds and to the extent it is overly broad and unduly burdensome, particularly in its solicitation of information not limited to IPL's Big Five Units. IPL objects to Request 1-23 on the grounds and to the extent it is vague and ambiguous. IPL objects to Request 1-23 on the grounds and to the extent it solicits information and documents not within IPL's possession or control and/or information or documents which are already in the public domain and accessible to CAC/SC. IPL further objects to Request 1-23 on the separate and independent grounds and to the extent the Request seeks a compilation, analysis or study that IPL has not performed and to which IPL objects to performing.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a-k. The economic analysis of the Big Five's continued operation was based on a comparison to a new CCGT. The analysis methodology used was not to determine what resource to replace a retired coal unit with, but rather to determine if IPL's compliance project was economic. This was achieved by comparing, economically, the Big Five to a CCGT based generation on a future life cycle evaluation. CCGT generation is the low cost resource selected in IPL's most recent IRP and is also the basis for the resource selection IPL is currently pursuing to replace the retiring Eagle Valley unit and fill other capacity requirements. And IPL's future life cycle evaluation demonstrated that it is more economic to install controls on the units than retire and replace with a CCGT.

Data Request 1-40. Refer to page 5 lines 8 through 12. Produce the IHS CERA Market Briefing Midwest Power Market Fundamentals document identified therein.

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection: IPL objects to CAC/SC Data Request 1-40 on the grounds and to the extent it solicits information that exceeds the scope of this proceeding and is not reasonably calculated to lead to the discovery of relevant or admissible evidence. IPL objects to the Request on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

See CAC/SC DR1-40 Confidential Attachment 1 (IHS CERA Market Briefing Midwest Power Market Fundamentals). This document is being provided pursuant to the November 27, 2012 Confidentiality Agreement between IPL and the Citizens Action Coalition of Indiana, Inc. and the Sierra Club.

Data Request 1-41. Refer to page 5 lines 3-4, where Mr. Ayers states: "The four Petersburg units and Harding Street Unit 7 all average well over 70% capacity factors and are expected to remain high utilization generating assets."

a. Please provide, individually by unit, the hourly net generation output of Petersburg units 1-4 and Harding Street unit 7 for the years 2008-2012, to the most recent record available.

b. Please provide a log or record of forced outages, maintenance outages, and other derating events at Petersburg 1-4 and Harding Street 7 for the years 2008-2012, to the most recent record available.

c. Please provide, by month and by unit, individually, any projections of generation, available capacity, and heat rate used or considered by the Company for this filing for Petersburg 1-4 and Harding Street 7 for the years 2012-2040.

d. Please provide the Company's projected effective forced outage rate (EFOR) for Petersburg 1-4 and Harding Street 7 for the years 2012-2040.

e. If EFOR is expected to decrease in any future year relative to the current day, please explain the mechanism by which this would occur and any maintenance costs incurred in such a decrease.

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection: IPL objects to CAC/SC Data Request 1-41 on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. See CAC/SC DR1-41a, Attachment 1 (Big Five Generation 2008-2012).

b. See CAC/SC DR1-41b, Attachment 1 (Big 5 2008 to Nov 2012 Event List).

c. See CAC/SC DR1-41c, Confidential Attachment 1 (MATS1V1 – Ventyx Select Data Assmptions_Outputs 12_19_12), provided pursuant to the November 27, 2012 Confidentiality Agreement between IPL and the Citizens Action Coalition of Indiana, Inc. and the Sierra Club. See also CAC/SC DR1-41c, Attachment 2 (MATS1D-Tate-SummerRatedCapacity_Projection_10_11a).

d. The targeted EFOR rate for Petersburg 1-4 and Harding Street 7 is 5.55%.

e. The actual annual EFOR rates for individual units will vary around this targeted EFOR, with generally better than target performance the years following a major scheduled overhaul, and generally worse than target in the years immediately preceding a scheduled overhaul.

Data Request 1-43. Refer to page 6 line 16 through page 7 line 17.

a. Produce the "base case analysis" referenced therein, including the spreadsheet evaluation and any workpapers in machine readable format with formulas intact.

b. Identify the base case modeling assumptions used in such analysis, and explain how those assumptions were derived from "IPL's most recent internal, CERA (CERA 2012 Report), and Ventyx (Ventyx 2012 Spring Reference Case) base case modeling assumptions."

c. Identify the annual capacity factor for the CCGT that you assumed in your base case analysis for each of 2015 through 2040.

d. Please provide basic specifications for the "lower capital cost CCGT" as used here, including but not limited to capacity, expected overnight capital cost, expected construction time and annual capital requirements during construction, annual fixed operations and maintenance (O&M) costs, variable O&M costs, any other expected ongoing capital expenses, heat rate, EFOR, and expected operating life.

e. Please identify the other resources considered for evaluation aside from the "lower capital cost CCGT." If the Company did not examine other resources, please explain why not in detail. Please provide the same basic specifications as in (d) above, as available, for these other resources.

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection: IPL objects to CAC/SC Request 1-43 on the grounds and to the extent it is overly broad and unduly burdensome. IPL further objects to the Request on the grounds and to the extent it is vague and ambiguous. IPL further objects on the grounds that the Request solicits confidential, proprietary, competitively-sensitive and/or trade secret information of IPL or a third party.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. The base case analysis was provided in Mr. Ayers' workpapers provided previously. The base case analysis is identified in tabs "Pete MAT (BE with Fuel)" and "CCGT (Base with Fuel)."

b. The base case modeling assumptions and description of their use are set forth in Mr. Ayers' prefiled testimony and workpaperss. Due to the lack of specificity in the question, IPL cannot otherwise determine what information is solicited.

c. The comparative analysis assumed that a CCGT would be dispatched at a 65% capacity factor for the evaluation period.

d. The CCGT profile and cost estimates are directly from CERA 2012 Midwest report. Please see Mr. Ayers' workpaper spreadsheet – tab: "16 CERA New Plant Cost" for the cost profile.

e. A CCGT was the selected least cost resource identified in IPL's most recent IRP. Since a CCGT was lower cost than other competing resources, it makes economic sense for the MATS economic life cycle evaluation to compare the Big Five to the lowest cost alternative resource.

Data Request 1-46. Refer to page 7, lines 13-15.

a. Please confirm that the Company performed the "base case analysis" for all Petersburg units simultaneously, rather than for each of Petersburg 1-4 units individually.

b. Did the Company ever review the outcome of a similar analysis for each of Petersburg units 1-4 individually, rather than as a single entity? If not, why not? Please be specific and detailed.

c. If the Company did review the outcome of a unit-by-unit analysis for Petersburg units 1-4, please provide the date, outcome, and workpapers associated with such analyses.

d. Confirm that in Mr. Ayers analysis, both the coal unit and natural gas replacement option are evaluated over a 25 year span. If not, please specify the analysis period for each coal unit and natural gas replacement unit.

e. Confirm that Mr. Sloat's analysis is conducted over a 20-year period (see Sloat page 26, A48).

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection:

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. Several evaluations were performed that addressed both. First, IPL performed a base case analysis considering the entire Petersburg plant. Looking at the plant as a whole makes sense because MATS compliance for PM, Hg, and HCl and other environment compliance limits including SO2 and NOx are plant or system based, requiring plant or system compliance optimization. The O&M costs are plant based as well with all units sharing common costs. IPL also performed an analysis that considered each unit individually.

b. Yes. As identified in Q22 of Mr. Ayers' testimony IPL looked specifically at the smallest unit – Petersburg 1, and the unit receiving the highest cost controls – Petersburg 2. This evaluation used the same comparative evaluation as the plant evaluation, but used unit specific MATS and other future environmental costs. These results are discussed in the response to Q22 and in Exhibit JMA-4 included with Mr. Ayers' testimony. As discussed in Q23 of this testimony, and shown in Exhibit JMA-4, Petersburg Units 3 and 4 were individually evaluated as well.

As stated in (a) above, this life cycle evaluation does not include any additional costs that could be imposed on the remaining units and thus IPL customers by an actual individual unit retirement.

c. As stated above in (a) and (b), the evaluation outcomes are included in Q22 and Q23 of Mr. Ayers' testimony and in his Exhibit JMA-4.

d. Yes, Mr. Ayers used 25 years for the life cycle cost comparison time period in the Big Five life cycle resource evaluation.

e. Confirmed. Mr. Sloat used 20 years for the MATS evaluation time period in evaluating the control technology plan.

Data Request 1-47. Refer to page 7, lines 15 and 16.

a. Please provide the "CERA 2012 Report" as provided to the Company, with any accompanying documentation.

b. Please provide the "Ventyx 2012 Spring Reference Case" as provided to the Company, with any accompanying documentation.

c. To the extent not already provided, please provide the numeric values used and relied upon by the Company from the CERA 2012 Report and Ventyx 2012 Spring Reference Case.

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection: IPL objects to CAC/SC Request 1-47 on the grounds and to the extent that the Request asks IPL to disclose confidential, proprietary, competitively-sensitive and/or trade secret information of IPL or a third party.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. See response to CAC/SC Data Request 1-40.

b. See CAC/SC DR 1-47b, Confidential Attachment 1 (Midwest_Spring 2012_Power_Reference_Case_-_Data_Supplement_IPL) and CAC-SC DR 1-47b, Confidential Attachment 2 (Ventyx Assumptions). These documents are being provided pursuant to the November 27, 2012 Confidentiality Agreement between IPL and the Citizens Action Coalition of Indiana, Inc. and the Sierra Club.

c. This information was previously provided in Mr. Ayers' testimony and workpapers.

Data Request 1-48. Refer to page 7 line 20 through page 8 line 2. For Petersburg units 1-4, and Harding Street unit 7, provide the following on an annual basis from 2012 through 2040 for each unit, individually. *(Note: for the purposes of the questions below, "All Environmental Projects" is defined here as the "Petersburg Project", the "Harding 7 Project", and "Other Environmental" projects as shown in JMA-2*)

a. Net available summer capacity, exclusive of all environmental projects

b. Heat rate, exclusive of all environmental projects

c. Fixed O&M, exclusive of all environmental projects

d. Variable O&M, exclusive of all environmental projects

e. Fuel costs, exclusive of all environmental projects

f. Expected capital expenditures, exclusive of all environmental projects

g. Net available summer capacity, inclusive of all environmental projects

h. Heat rate, inclusive of all environmental projects,

i. Fixed O&M, inclusive of all environmental projects

j. Variable O&M, inclusive of all environmental projects

k. Fuel costs, inclusive of all environmental projects

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection: IPL objects to Request 1-48 on the grounds and to the extent the Request seeks a compilation, analysis or study that IPL has not performed and to which IPL objects to performing. IPL further objects on the grounds that the Request solicits confidential, proprietary, competitively-sensitive and/or trade secret information of IPL or a third party.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a-b. See response to CAC-SC DR 1-41c.

c-d. For the evaluation IPL used forecast total plant O&M (fixed and variable), including existing FGD and SCR costs that are part of Petersburg plant O&M. See CAC-SC DR 1-48cd, Attachment 1 (MATS1A-Tate-Total Capital + Expense O&M – Summary by Group1). These are not broken out by unit and would include all common plant costs as well. These costs are identified in worksheet tab "O&M+Fixed 10-year (2)" for the period

2012 through 2021, and escalated thereafter. For this evaluation the variable O&M was included in the total O&M number.

The HS-7 evaluation was based on comparison using the Petersburg plant O&M. The Harding Street station plant O&M, even with all plant O&M was fully attributed to coal-fired generation was lower than Petersburg plant O&M on a $/kW/year basis. The HSS plant O&M is provided in CAC-SC DR 1-48cd, Attachment 1 (MATS1A-Tate-Total Capital + Expense O&M – Summary by Group1).

e. Not applicable. Mr. Ayers addressed fuel costs through his spark and dark spread analysis.

f. Expected non-environmental capital expenditures are included in the fixed capital and expense O&M identified in (c) above.

g. An estimate for which the units' capacity ratings will be reduced is:

P1=1185kW

P2=3079 kW

P3=4042 kW

P4=2990 kW

HS7=2439 kW

h. IPL has not estimated the revised heat rates.

i-j. For the evaluation IPL used total plant O&M (fixed and variable) for existing plant operations including FGD and SCR equipment (see CAC-SC DR 1-48cd, Attachment 1 (MATS1A-Tate-Total Capital + Expense O&M – Summary by Group1)), and added MATS related O&M costs as identified in the S&L Report presented by witness Sloat and other future environmental costs (as estimated in Exhibit JMA-2). For this evaluation, the variable O&M was included in the total O&M number (see CAC-SC DR 1-48cd, Attachment 1 (MATS1A-Tate-Total Capital + Expense O&M – Summary by Group1)) at the capacity factors identified.

k. The fuel costs would not change under the proposed Compliance project. See response to (e) above.

SUPPLEMENTAL RESPONSE 1.48 (c, d, i, j):

IPL in its evaluation used a total O&M cost including variable and fixed capital and expense O&M for Petersburg plant based on IPL's ten year projections of total O&M costs, and added MATS total O&M and Other Future Environmental total O&M to provide a forecast total O&M. A breakdown of O&M was not performed directly nor was it needed for IPL's baseload comparative evaluation.

In the spirit of cooperation, IPL has broken out these items as shown in CAC/SC DR 1-48 Supplemental Response Attachment 1. These numbers are in 2012$ and escalated at 2.5%. Mr. Ayers' prefiled testimony and exhibits used 26.0/kw-yr for other environmental total O&M for Pete plant. This cost should have been $16.0/kw-yr (2015$) based on the O&M estimates correctly identified in Exhibit JMA-2. As a result the prefiled analysis included with Mr. Ayers' testimony and exhibit overstated coal/Pete O&M for "other enviro". This is corrected in CAC/SC DR 1-48 Supplemental Response Attachment 1.

Indianapolis Power & Light Company
Cause No. 44242
CAC-SC DR 1-48 Supp Response Attachment 1

IPL's Big Five Capital and Expense O&M Cost Estimates (in 2012$).

O&M ($M)		HS-7	Pete 1	Pete 2	Pete 3	Pete 4
BASE	Variable	7.6	3.0	6.0	7.9	6.9
	Fixed	31.0	12.8	23.6	28.8	30.1
MATS	Variable	4.9	3.8	4.7	6.0	14.8
	Fixed	1.0	1.1	0.8	0.4	1.0
OTHER	Variable	2.4	2.3	3.5	3.1	4.1
	Fixed	2.4	2.3	3.5	3.1	4.1
TOTAL	Variable	14.9	9.1	14.2	17.0	25.8
	Fixed	34.5	16.3	27.9	32.3	35.2

VARIABLE O&M ($/MWH)	HS-7	Pete 1	Pete 2	Pete 3	Pete 4
BASE	2.6	1.8	2.0	2.1	1.8
MATS	1.7	2.4	1.6	1.6	3.9
OTHER	0.8	1.5	1.2	0.8	1.1
TOTAL	5.1	5.7	4.7	4.5	6.8

CAPEX SUMMARY ANALYSIS--TOTAL COMPANY
2012-2021 BUDGET

$000

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
GROUP										
Power Supply (Non-Outage)										
Petersburg	8,725	10,365	13,362	18,644	12,407	11,997	11,500	12,481	9,414	11,224
Harding Street	4,818	4,513	2,875	1,603	3,727	4,494	3,535	3,051	6,969	7,160
Eagle Valley	955	1,422	1,561	872	2,109	-	-	-	-	-
Total Power Supply (Non-Outage)	**14,498**	**16,300**	**17,798**	**21,119**	**18,243**	**16,491**	**15,035**	**15,532**	**16,383**	**18,384**
Power Supply (Outage)										
Petersburg	17,667	24,665	10,399	16,230	6,808	9,550	7,707	17,866	55,055	32,039
Harding Street	12,934	2,650	4,737	5,544	5,696	558	1,639	2,980	(726)	932
Eagle Valley	260	50	-	-	37,509	-	-	-	-	-
Total Power Supply (Outage)	**30,861**	**27,365**	**15,136**	**21,774**	**50,013**	**10,108**	**9,346**	**20,846**	**54,329**	**32,971**
Supply Coordination	-	500	7,920	-	-	-	-	-	-	-
Power Supply Environmental	3,950	2,450	4,316	6,864	2,550	6,411	5,816	8,568	1,392	6,401
TOTAL POWER SUPPLY	**49,309**	**46,615**	**45,170**	**49,757**	**70,806**	**33,010**	**30,197**	**44,946**	**72,104**	**57,756**
Customer Operations										
Power Delivery	80,862	72,081	78,301	81,061	74,379	75,601	76,430	79,208	80,720	81,194
Customer Service	358	735	-	-	-	-	-	294	-	-
TOTAL CUSTOMER OPS	**81,220**	**72,816**	**78,301**	**81,061**	**74,379**	**75,601**	**76,430**	**79,502**	**80,720**	**81,194**
Corporate										
Financial Services	120	-	-	-	-	-	-	-	-	-
Information Technology	8,562	5,631	5,810	15,520	14,545	2,670	3,670	7,270	5,770	3,770
Human Resources	40	-	-	-	-	-	-	-	-	-
General Counsel	245	-	-	-	-	-	-	-	-	-
Community Relations	81	-	-	-	-	-	-	-	-	-
Safety	30	-	-	-	-	-	-	-	-	-
Corporate CAPEX	-	468	471	484	499	512	526	539	555	571
TOTAL CORPORATE	**9,078**	**6,099**	**6,281**	**16,004**	**15,044**	**3,182**	**4,196**	**7,809**	**6,325**	**4,341**
TOTAL GROUP	**139,607**	**125,530**	**129,752**	**146,822**	**160,229**	**111,793**	**110,823**	**132,257**	**159,149**	**143,291**
Pete 4 FGD Upgrade	1,859	-	-	-	-	-	-	-	-	-
Project Development	1,369	4,373	779	184	189	194	200	205	211	216
TOTAL CAPEX	**142,835**	**129,903**	**130,531**	**147,006**	**160,418**	**111,987**	**111,023**	**132,462**	**159,360**	**143,507**
Unspecified CAPEX Pool	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
TOTAL CAPEX INCL. UNSPECIFIED POOL	**144,835**	**131,903**	**132,531**	**149,006**	**162,418**	**113,987**	**113,023**	**134,462**	**161,360**	**145,507**
MTC	141,776	127,703	131,931	149,006	162,418	113,987	113,023	134,462	161,360	145,507
GROWTH	1,200	4,200	600	-	-	-	-	-	-	-
ENV	1,859	-	-	-	-	-	-	-	-	-
DOE Grants shown as Other Investing Not CapEx	(6,016)	(1,065)	-	-	-	-	-	-		-

O&M + OTHER SUMMARY ANALYSIS--TOTAL COMPANY
2011-2021

$000	2011 Actual	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
GROUP											
Power Supply (Non-Outage)											
Petersburg	58,110	59,971	59,717	60,888	63,206	64,546	66,810	68,792	70,926	72,791	75,103
Harding Street	23,070	22,319	23,232	24,873	25,585	23,740	25,349	25,355	26,063	27,286	27,840
Eagle Valley	11,457	11,580	11,924	12,675	12,699	-	-	-	-	-	-
Supply Coordination	4,455	4,343	4,681	4,326	4,450	4,578	4,709	4,844	4,983	5,126	5,273
Total Power Supply (Non-Outage)	97,092	98,213	99,554	102,762	105,940	92,864	96,868	98,991	101,972	105,203	108,216
Power Supply (Outage)											
Petersburg	39,016	14,263	31,745	20,089	22,674	20,811	20,235	15,244	19,270	46,816	33,456
Harding Street	1,191	9,610	8,035	4,034	8,425	6,659	1,245	7,294	14,113	1,142	7,275
Eagle Valley	2,645	2,633	1,734	1,852	2,403	-	-	-	-	-	-
Total Power Supply (Outage)	42,852	26,506	41,514	25,975	33,502	27,470	21,480	22,538	33,383	47,958	40,731
TOTAL POWER SUPPLY	139,944	124,719	141,068	128,737	139,442	120,334	118,348	121,529	135,355	153,161	148,947
Customer Operations											
Power Delivery	56,210	61,206	63,736	65,512	67,254	69,065	70,970	72,895	74,862	77,071	79,184
Customer Service	13,294	14,150	14,193	14,547	14,947	15,358	15,780	16,214	16,660	17,118	17,589
TOTAL CUSTOMER OPS	69,504	75,356	77,929	80,059	82,201	84,423	86,750	89,109	91,522	94,189	96,773
Corporate											
Financial Services	6,644	6,866	7,161	7,138	7,320	8,132	8,193	8,391	8,723	8,800	9,014
Information Technology	14,995	15,595	17,473	17,487	18,043	18,754	19,316	19,892	20,482	21,087	21,707
Human Resources	2,360	2,222	2,355	2,397	2,461	2,527	2,595	2,665	2,736	2,810	2,885
Internal Audit	125	301	309	317	325	334	344	353	363	373	383
Corporate Affairs	2,976	2,626	2,721	2,795	2,871	2,949	3,030	3,112	3,197	3,284	3,374
General Counsel	10,574	8,590	8,856	9,077	9,327	9,584	9,847	10,118	10,396	10,682	10,976
Community Relations	4,638	4,686	4,978	5,102	5,243	5,387	5,535	5,687	5,843	6,004	6,169
CEO	646	678	705	723	743	763	784	805	828	850	874
Safety	1,084	1,224	1,229	1,263	1,298	1,335	1,373	1,412	1,452	1,493	1,535
TOTAL CORPORATE	44,042	42,788	45,787	46,299	47,631	49,765	51,017	52,435	54,020	55,383	56,917
TOTAL GROUP	253,490	242,863	264,784	255,095	269,274	254,522	256,115	263,073	280,897	302,733	302,637
Environmental											
Petersburg	4,107	7,152	7,351	6,979	7,784	7,313	8,371	8,603	9,309	9,330	9,562
Harding Street	8,717	11,916	12,629	11,647	11,993	12,486	11,535	12,909	13,546	13,590	13,382
Eagle Valley	125	78	80	82	84	-	-	-	-	-	-
ENVIRONMENTAL	12,949	19,146	20,060	18,708	19,861	19,799	19,906	21,512	22,855	22,920	22,944
TOTAL O&M + OTHER	266,439	262,009	284,844	273,803	289,135	274,321	276,021	284,585	303,752	325,653	325,581

Data Request 1-50. Refer to page 7 line 20 through page 8 line 2. Did the Company review, estimate, or calculate any ongoing capital expenditures in 2013-2015 that could be avoided in the event that any of the units are retired in 2015 or 2016? If not, why not? If so, please provide a list of the projects that could otherwise be avoided and their estimated or budgeted cost.

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection:

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

No. Costs from 2013-2015 were not included in the future life cycle cost evaluation. These costs would however be included in a retirement evaluation if the future life cycle evaluation had indicated a unit's economic viability was in question. A retirement evaluation, if determined necessary, would also include the premature unit retirement costs and timing impacts, an economic assessment of common O&M shared by plant to determine what O&M is actually avoided, and any additional environmental compliance costs for plant and system based environmental rules, such as NOx. This additional retirement evaluation was not needed as the Big Five units and Compliance plan showed superior economics.

Data Request 1-62. Refer to page 14 line 20 through page 15 line 2.

a. Explain how it was determined that reducing coal's forecast energy advantage by half would reflect a scenario involving "perpetual low long term natural gas prices or some form of restrictive climate change legislation."

b. Identify what level of natural gas prices and/or carbon price from climate change legislation would be needed to eliminate each individual coal units forecast energy advantage as stipulated in this docket (see equivalent value in Petitioners Exhibit JMA-3, line "Net Coal Energy Margin Advantage")

c. Did the Company consider a stress test in which the current margin, as cited on page 9 line 19, is maintained? If so, produce the results of this stress test and workpapers supporting the assumptions and results of this test.

d. Did the Company consider a stress test in which the margin between coal and gas is inverted? If so, produce the results of this stress test and workpapers supporting the assumptions and results of this test.

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection: IPL objects to the CAC/SC Request 1-62 on the grounds and to the extent it seeks an analysis, calculation, or compilation which has not already been performed and which IPL objects to performing. IPL further objects to the Request on the grounds and to the extent it is vague and ambiguous.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. The evaluation methodology stress tested the base forecast case results based on two possible coal energy margin risks lower than forecast natural gas prices or some future, but unknown, CO2 cost to see if the results changed. Cutting coal's energy margin advantage in half from base case forecast was considered a sufficiently robust test or scenario to the base case forecast. There was no specific forecast of gas or CO2 prices or when such a CO2 cost would be incurred or how any CO2 allowances would be distributed. The stress test assumed "stresses" at the beginning of the evaluation (2015).

b. IPL did not perform this analysis. The stress test performed at half the base case energy margin was used to validate IPL MATS control strategy and Big Five resources. This additional analysis is not considered necessary to the evaluation and determination.

c. The question is vague because the words "current margin" are undefined. A case where the energy margin is maintained at 2014-2016 levels (and not escalated thereafter) would not economically challenge IPL's Big Five coal fired generation as severely as the energy stress test that IPL did perform. Stated another way, IPL's stress test bounds this hypothetical scenario.

d. No.

Data Request 1-64. Refer to page 15 lines 12 through 18.

a. Produce the "energy stress test scenario" referenced therein, including any modeling, spreadsheet evaluation, and workpapers in machine readable format with formulas intact.

b. To the extent not already provided, produce the commodity prices (i.e. coal, natural gas, CO2, market energy, and capacity price projections) assumed in the "energy stress test scenario" from 2012 through 2040.

c. To the extent not already provided, produce the capital and ongoing fixed and variable O&M costs for any environmental equipment or replacement capacity assumed in the "energy stress test scenario" from 2012 through 2040.

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection:

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. The energy stress test PVRR scenario evaluation is identified in Mr. Ayers' workpaper worksheet tab "Pete MATs (BE wo fuel)" and "CCGT (Base wo fuel)"

b. The energy stress test has the same assumptions as the base case analysis, except that the future coal energy margin advantage is reduced in half from the base forecast.

c. The energy stress test has the same capital and ongoing O&M assumptions as the base case analysis, except that the future coal energy margin advantage is reduced in half from the base forecast.

Data Request 1-70. Refer to Petitioner's Exhibit JMA-2.

a. For each of the CAPEX costs identified therein:

i. Identify the basis for each cost estimate
ii. Produce any documents or analyses supporting each cost estimate
iii. Identify in what year the costs are assumed to be incurred
iv. Identify in what year the cost figures are reported
v. State whether the cost figures are in real or nominal dollars

b. For each of the O&M costs identified therein:

i. Identify the basis for each cost estimate
ii. Produce any documents or analyses supporting each cost estimate
iii. Identify the first year in which each cost is assumed to be incurred
iv. State whether each cost is assumed to be incurred in each year thereafter through 2040
v. Identify in what year the cost figures are reported
vi. State whether the cost figures are in real or nominal dollars

c. State whether any costs were assumed for compliance with the 1-hour SO_2 NAAQS

i. If so, identify the amount of such costs and what they would be incurred for.
ii. If not, explain why not.

d. State whether any costs were assumed for compliance with expected Ozone NAAQS

i. If so, identify the amount of such costs and what they would be incurred for.
ii. If not, explain why not.

e. State whether any costs were assumed for compliance with the federal effluent limitation guidelines.

i. If so, identify the amount of such costs and what they would be incurred for.
ii. If not, explain why not.

This Data Request will be addressed in supplemental response.

SUPPLEMENT:

Objection: IPL objects to CAC/SC Data Request 1-70 on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret. IPL further objects to the Request to the extent it solicits seek information that is subject to the attorney-client, work product, settlement negotiation or other applicable privileges.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a.

i. The cost estimates as identified in Exhibit JMA-2 were estimated and compiled by Dwayne Burke, former Director of Environmental Affairs, IPL, and based in part on various studies completed by IPL and Mr. Burke's industry knowledge in these areas. Mr. Burke recently passed on November 18th of this year.

IPL has completed a study which included costs for a Unit 4 SCR. One study (Multipollutant Emissions Compliance Study, provided as CAC-SC DR Q1-14, Attachment 4) provided a cost estimate of $90M in 2005 dollars.

IPL has completed a study of the impacts of CCR (ash) Rules and costs were developed for such study (Evaluation of Effects of Proposed CCR Rule, provided as CAC-SC DR Q1-14, Attachment 2). Costs were estimated ranging from $21M-$30M for the Petersburg plant in 2010 dollars. Estimated costs for Harding Street Unit 7 range from $15M-$18M in 2010 dollars.

IPL is currently in the process of performing a Wastewater Treatment Study to determine costs associated with compliance with the new NPDES Permit requirements. This study is still underway and costs are still under development. Current preliminary estimates range from $75M-$250M.

IPL has performed a study of the impacts of 316(b) and cost estimates were developed for such study (316(b) APEX, provided as CAC-SC DR Q1-14, Attachment 1). Costs were estimated ranging from $4M-$152M for Petersburg Units 1 & 2 combined in 2012 dollars. Costs were estimated at $3M for Harding Street Unit 7 in 2012 dollars.

ii. See CAC-SC DR Question 1-14, Attachments 1, 2 and 4, which provide analysis supporting the cost estimates for 316(b), CCR, and NAAQS, respectively.

iii. All costs were assumed to be incurred in 2015.

iv. The cost figures are in 2012 dollars.

v. The cost figures are in 2012 dollars.

b.

i. The cost estimates as identified in Exhibit JMA-2 were estimated and compiled by Dwayne Burke, former Director of Environmental Affairs, IPL, and based in part on various studies completed by IPL and Mr. Burke's industry knowledge in these areas. Mr. Burke recently passed on November 18th of this year.

IPL has completed a study which included costs for a Unit 4 SCR. One study (Multipollutant Emissions Compliance Study, provided as CAC-SC DR Q1-14, Attachment 1) provided a cost estimate of $2.3M annually in 2005 dollars.

IPL has completed a study of the impacts of CCR (ash) Rules and costs were developed for such study (Evaluation of Effects of Proposed CCR Rule, provided as CAC/SC DR Q1-14, Attachment 2). Costs were estimated ranging from $3M-$37M annually for the Petersburg plant in 2010 dollars. Costs were estimated ranging from $3M-$14M annually for Harding Street Unit 7 in 2010 dollars.

IPL is currently in the process of performing a Wastewater Treatment Study to determine costs associated with compliance with the new NPDES Permit requirements. This study is still underway and O&M costs have not yet been development.

IPL has performed a study of the impacts of 316(b) and cost estimates were developed for such study (316(b) APEX, provided as Attachment 1 to Q1-14). Costs were estimated ranging from $1M-$6M annually for Petersburg Units 1 & 2 combined in 2012 dollars. Costs were estimated at $0.15M-$0.4M for Harding Street Unit 7 in 2012 dollars.

ii. See CAC/SC DR Question 1-14, Attachments 1, 2 and 4, which provide analysis supporting the cost estimates for 316(b), CCR, and NAAQS, respectively.
iii. The first year in which each cost is assumed to be incurred is 2015.
iv. Yes, each cost is assumed to be incurred in each year thereafter through 2040.
v. The cost figures are in 2012 dollars.
vi. The cost figures are in 2012 dollars.

c. No.

i. Not applicable.
ii. IPL does not believe any costs will be associated with the 1-hour SO2 NAAQS. The Big Five Units are equipped with FGDs. Further, bypass of the FGDs will be minimized by upgrades to those FGDs which are being completed as part of the MATS Compliance Plan.

d. Yes.

i. Costs for an SCR on Petersburg Unit 4. The SCR would reduce emissions of NOx, which are a precursor to ozone. These costs are assumed as a conservative measure. At this time, it is uncertain whether an SCR will be required for compliance with the Ozone NAAQS.

ii. Not applicable.

e. No.

i. Not applicable.

ii. A proposed rule has not yet been issued for the federal effluent limitation guidelines. The proposed rule is expected to be issued in April 2013. IPL has included cost for compliance with new NPDES permit limitations, some of which may overlap with costs for compliance with the effluent limitation guidelines.

Refer to the Verified Direct Testimony of James Ayers:

Data Request 2-1. Refer to page 5 lines 3 to 8.

a. Please provide the Company's most recent long-term forecast of annual requirements for native load and for off-system sales respectively.

b. Is the Company's expectation that the five units will remain "high utilization generating assets" based to any extent on a projection of off-system sales? If so, please provide that projection, including any workpapers, and identify the annual margin the Company expects from those off-system sales.

c. Please provide all support for the position that "replacement generation would typically be represented by replacement coal-fired generation."

d. Does the position that "replacement generation would typically be represented by replacement coal-fired generation" imply that the Company would not evaluate a range of resource options when faced with the need to replace existing capacity and generation from that capacity? If so, please provide the rationale for not evaluating a range of resource options. If not, identify the range of resource options that would be considered.

Objection:

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. IPL's retail sales forecast for the period 2013-2022 (with and without DSM) is:

IPL Retail Sales Forecast (MWH)

		Net of DSM
2013	14,307,125	14,118,020
2014	14,550,874	14,241,352
2015	14,838,924	14,409,551
2016	15,128,076	14,567,446
2017	15,223,205	14,514,876
2018	15,302,963	14,435,599
2019	15,393,364	14,378,372
2020	15,513,376	14,422,313
2021	15,579,309	14,469,672
2022	15,683,984	14,581,005

IPL does not have any firm off-system sales contracts. IPL off-system sales are entirely the result of hourly spot sales opportunities that occur if

IPL generation clears the MISO market in excess of IPL's hourly retail load obligations. Through November 2012 IPL off-system sales were approximately 1,063,000 MWH. For calendar 2011 IPL off-system sales totaled approximately 1,418,000 MWH.

b. No. The company's capacity factor projections and expectation that the Big Five will remain "high utilization generating assets" are based on dispatch of those generating units into the MISO power market.

c. This statement provided an historic context to replacement baseload capacity in the Midwest being primarily coal generation (with some nuclear), and not gas-fired generation. The Direct Testimony of Mr. Ayers then identifies a CCGT as an appropriate replacement resource for his economic evaluation, and this is the resource against which IPL's Big Five were evaluated.

d. No. The range of economic resources considered are identified in IPL's most recent IRP. Any future CPCN for additional new generation would include an evaluation of those options.

Data Request 3-3. Does the Company currently have in its possession any hourly energy market price forecasts for MISO that extend beyond the year 2016? If so:

a. List such forecasts, their source, date, and use by the Company.

b. Provide such forecasts as either provided to the Company, used by the Company in any capacity, or created by or on behalf of the Company.

c. Provide any sensitivities or alternative futures explored, examined, or used by the Company in any capacity.

Objection:

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. The hourly market energy prices are developed using the monthly on-peak and off-peak market energy price forecasts from Ventyx as identified in the response to CAC/SC DR 3-4. The third party monthly energy price forecasts are applied to historic hourly price profiles to develop a set of hourly market prices for model analysis.

b. See CAC-SC DR 3-3, Attachment 1 (IPL Hourly Prices).

c. Sensitivities and alternate futures are developed in conjunction with the biennial IRP filings. See CAC-SC DR 1-13, Attachment 1 (IPL Public 2011 IRP), Section 4 pages 39-62.

Data Request 3-4. Does the Company currently have in its possession any energy market price forecasts for MISO, other than at an hourly resolution, that extend beyond the year 2016?

a. List such forecasts, their source, date, and use by the Company.

b. Provide such forecasts as either provided to the Company, used by the Company in any capacity, or created by or on behalf of the Company.

c. Provide any sensitivities or alternative futures explored, examined, or used by the Company in any capacity.

Objection: IPL objects to Request 3-4 on the grounds and to the extent the request seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. The primary source used by IPL for MISO energy market price forecasts beyond 2016 is Ventyx.

b. The Ventyx MISO monthly on-peak and off-peak monthly market price forecasts can be found in "Tab 14. Monthly MCPs" of the Ventyx Spring 2012 Power Reference Case file previously provided as CAC-SC DR 1-47b, Confidential Attachment 1.

c. Sensitivities and alternate futures are developed in conjunction with the biennial IRP filings. See CAC-SC DR 1-13, Attachment 1 (IPL Public 2011 IRP), Section 4 pages 39-62.

Data Request 3-5. Does the Company currently have in its possession any capacity market forecasts for MISO that extend beyond the year 2016? If so:

a. List such forecasts, their source, date, and use by the Company.

b. Provide such forecasts as either provided to the Company, used by the Company in any capacity, or created by or on behalf of the Company.

c. Provide any sensitivities or alternative futures explored, examined, or used by the Company in any capacity.

Objection: IPL objects to Request 3-5 the grounds and to the extent the request seeks information that is confidential, proprietary, competitively-sensitive and/or trade secret.

Response: Subject to and without waiver of the foregoing objections, IPL provides the following response:

a. The primary source used by IPL for MISO capacity market forecasts beyond 2016 is Ventyx.

b. The Ventyx MISO capacity market forecasts can be found in "Tab 15. Capacity Prices" of the Ventyx Spring 2012 Power Reference Case file previously provided as CAC-SC DR 1-47b, Confidential Attachment 1.

c. Sensitivities and alternate futures are developed in conjunction with the biennial IRP filings. See CAC-SC DR 1-13, Attachment 1 (IPL Public 2011 IRP), Section 4 pages 39-62.

EXHIBIT JIF-4-CONFIDENITAL

CITED DATA REQUEST RESPONSES AND ATTACHMENTS

EXHIBIT B

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL"), AN INDIANA CORPORATION, FOR APPROVAL OF CLEAN ENERGY PROJECTS AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR CONSTRUCTION AND USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECTS THROUGH IPL'S ENVIRONMENTAL COMPLIANCE COST RECOVERY ADJUSTMENT ("ECCRA"); FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; FOR THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, AND OPERATION AND MAINTENANCE COSTS, UNTIL SUCH COSTS ARE REFLECTED FOR RATEMAKING PURPOSES, ALL PURSUANT TO IND. CODE §§ 8-1-2-6.1, 8-1-2-6.7, 8-1-2-6.8, 8-1-2-42(a), 8-1-8.4, 8-1-8.7, 8-1-8.8 AND 170 IAC 4-6-1 ET SEQ.	)	**CAUSE NO. 44242**

Direct Testimony of
Peter Lanzalotta

On Behalf of
Citizens Action Coalition of Indiana and Sierra Club

January 28, 2013

Q. Mr. Lanzalotta, please state your name, position and business address.

A. My name is Peter J. Lanzalotta. I am a Principal with Lanzalotta & Associates LLC, ("Lanzalotta"), 67 Royal Point Drive, Hilton Head Island, South Carolina 29926.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Citizens Action Coalition of Indiana, Inc. ("CAC") and Sierra Club. (collectively, "Joint Intervenors").

Q. Mr. Lanzalotta, please summarize your educational background and recent work experience.

A. I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelor of Science degree in Electric Power Engineering. In addition, I hold a Masters degree in Business Administration with a concentration in Finance from Loyola College in Baltimore.

I am currently a Principal of Lanzalotta & Associates LLC, which was formed in January 2001. Prior to that, I was a partner of Whitfield Russell Associates, with which I had been associated since March 1982. My areas of expertise include electric system planning and operation, economic studies, cost allocation, and reliability analyses. I am a registered professional engineer in the states of Maryland and Connecticut.

I have been involved with planning, operating, and economic issues related to electric utility systems as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities over a period exceeding thirty years.

I have presented expert testimony before the Federal Energy Regulatory Commission (FERC), United States District Court for the Southern District of Indiana, and before regulatory commissions and other judicial and legislative bodies in 25 states, the District of Columbia, and the Canadian Provinces of Alberta and Ontario. My clients have included utilities, state regulatory agencies, state ratepayer advocates, independent power producers, industrial consumers, the United States Government, environmental interest groups, and various city and state government agencies.

A copy of my current resume is included as Exhibit___(PJL-1) and a list of my testimonies is included as Exhibit___(PJL-2).

Q. What is the purpose of your testimony?

A. I was retained to review the extent to which IP&L ("Company") has studied the effects that retirement of any of its coal-fired Big Five generating units in Indiana would have on transmission system reliability. This testimony presents the results of my review.

Q. Please explain how you conducted your analyses.

A. I have reviewed the following information in our investigation:

i. The Company's testimony.

ii. The Company's responses to discovery questions submitted in this proceeding.

iii. MISO MTEP[1] Reports, which address transmission system reliability planning, for the past three years, as well as other MISO transmission planning documents.

iv) Portions of the Company's recent FERC Form 715 filings, which address transmission system reliability planning.

Q. Please summarize your conclusions.

A. My testimony concludes that the Company has not studied the effects of the possible retirement of any of the coal-fired generating units that the Company calls the Big Five Units on electric transmission system reliability, has not determined whether any such retirements would cause violations of required transmission reliability planning levels, and has not determined how expensive it would be to remedy any such violations.

Q. What level of transmission system reliability is mandatory for electric utility transmission system planning?

A. The reliability planning for electric transmission systems is governed by FERC and is administered and managed by the North American Electric Reliability Corporation (NERC), through regional councils.[2] NERC has mandatory transmission planning requirements that are largely included in NERC Standards TPL-001-0.1, TPL-002-0b, and TPL-003-0a which address planning requirements at projected peak loads five or more years into the future for normal system conditions, i.e., with no system

[1] MISO Transmission Expansion Plan

[2] RFC is the regional NERC Council in which the Company is a participant. The transmission planning coordinator for the Company is the Midwest Independent Transmission System Operator ("MISO") which addresses mandatory NERC transmission planning requirements.

contingencies,[3] for system conditions with all possible single contingencies, studied one at a time, and for system conditions with specified multiple contingencies.

Typically, under normal system conditions (no contingencies), all load-sensitive system elements, most typically transmission lines and substation transformers, will be loaded up to not higher than their normal maximum capabilities,[4] and all substation busses will be within normal voltage limits. Under single contingency conditions, electric service will typically be maintained to most firm loads, all load-sensitive system elements will be loaded up to not higher than their emergency maximum capabilities, and all substation busses will be within emergency voltage limits. Under multiple contingency conditions, firm loads may be dropped under certain conditions, but the electric system must not have a cascading outage, and those system elements remaining in service must be operating within emergency thermal and voltage limits. When system components are found, during such planning, to be loaded above the applicable capabilities, or are found to be at a voltage level outside the required range, this is typically referred to as a planning violation, which must be addressed before they actually occur.

FERC is currently considering a new NERC transmission system reliability standard, Standard TPL-001-2, which, if approved, will consolidate and replace the above referenced standards.[5]

[3] A contingency is an unplanned, forced outage of an electric system component, typically a transmission line, a substation transformer, or a generating unit.

[4] Typically referred to as thermal loading, since these operating capabilities are limited by the heat that a system component experiences as its loading increases.

[5] NERC TPL standards are available at http://www.nerc.com/page.php?cid=2|20.

Q. Please describe any study results provided by the Company that evaluate the effects of generating unit retirements on transmission system reliability.

A. CAC/SC DR 1-27 requested that the Company produce any analysis or assessment prepared by or for IPL of the impact that retirement of any of IPL's coal-fired generating units would have on capacity adequacy, transmission grid stability, generating unit operating cost, transmission grid support, voltage support, or transmission system reliability. The Company provided what is called a FCITC analysis (first contingency incremental transfer analysis) reflecting the retirement of a number of smaller oil-fired and coal-fired generating units, including Harding Street Units 3-6 and Eagle Valley 1-6. This analysis looked at the effect on transmission system import limits into the Company's service area when these generating units are retired and the remaining system is subjected to contingency conditions. The analysis report summarizes a number of system reinforcements needed to enable the system to handle the resultant power flows and to maintain required voltage level, including a new substation transformer and a number of other upgrades to existing transmission lines and substations at an estimated cost of about $18.3 million. The analysis does not address that retirement of any of the Big Five Units.

Q. Are there any indications in the transmission analyses provided by the Company as to the potential impact of retiring one or more of the Big Five generating units?

A. Yes. CAC/SC DR 1-25 requested that the Company produce a copy of any transmission adequacy studies (other than MTEP studies) performed in the past three years. These studies consistently refer to Harding Street Unit 7 as being most critical to maintaining area voltage levels. This suggests that the retirement of this generating unit could, depending on where replacement generating capacity or other system resources are located, require the addition of voltage support or other system reinforcements.

Q. Does the potential need for such voltage support or other system reinforcement foreclose the potential for retiring Harding Street Unit 7?

A. Not necessarily. Instead, if retirement appears to be a potential least cost option for Harding Street Unit 7, then the open and transparent evaluation of reliability impacts and solutions discussed below should be carried out.

Q. Why is it necessary for the Company to have determined whether the retirement of one or more of its Big Five coal-fired generating units would result in transmission system reliability planning violations?

A. When trying to decide on the most economical option, where retrofitting a generating unit for continued operation versus retiring the generating unit are among the options under consideration, it is necessary to know what the system planning reliability impacts are on the transmission system as a result of retiring each unit, as well as what it will cost to remedy these reliability impacts. Without this information, it is difficult for the Company, intervenors, or the Commission to evaluate the transmission system reliability impacts resulting from a generating unit retirement, or the costs needed to address these impacts, and to determine the least-cost choice between i) generating unit retirement and ii) unit retrofitting and continued operation.

While there are sometimes significant transmission system reliability problems that need to be addressed before a generating unit can be retired, there are a wide range of options for addressing transmission system planning reliability impacts, some of which are relatively moderate in terms of cost and time required for implementation. Some potential fixes can be in the range of costs that are not likely to change the economics of retrofitting versus retiring any given unit. Since these transmission system reliability impacts of generating unit retirements have not been studied, except as described above, it is impossible to say how extensive or expensive it could be to mitigate any transmission system reliability impacts that might result from such retirements.

Even if there are significant reliability fixes that need to be made to allow for the retirement of a generating unit, there are processes in place to allow for such fixes to occur in a timely manner. The TPL transmission system planning standards discussed above require regularly performed planning studies that look into the future, so as to identify reliability concerns before they occur.

The Commission should require that any claims that purported transmission reliability impacts should block the otherwise economic retirement of a generating unit be substantiated. If faced with such reliability claims, the Commission should require an evaluation of reliability impacts and allow for an open and transparent review process in which interested parties are able to review and submit testimony regarding such evaluation.

Q. Does this conclude your direct testimony?

A. Yes.

EXHIBIT PJL-1

Prior Experience Of Peter J. Lanzalotta

Mr. Lanzalotta has more than thirty-five years experience in electric utility system planning, power pool operations, distribution operations, electric service reliability, load and price forecasting, and market analysis and development. Mr. Lanzalotta has appeared as an expert witness on utility reliability, planning, operation, and rate matters in more than 100 proceedings in 24 states, the District of Columbia, the Provinces of Alberta and Ontario, before the Federal Energy Regulatory Commission, and before U. S. District Court. He has developed evaluations of electric utility system cost, value, reliability, and condition. He has participated in negotiations or other interactions between utilities and customers or regulators in more than ten states regarding transmission access, the need for facilities, electric rates, electric service reliability, the value of electric system components, and system operator structure under wholesale competition.

Prior to his forming Lanzalotta & Associates LLC in 2001, he was a Partner at Whitfield Russell Associates for fifteen years and a Senior Associate for approximately four years before that. He holds a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration with a concentration in Finance from Loyola College of Baltimore.

Prior to joining Whitfield Russell Associates in 1982, Mr. Lanzalotta was employed by the Connecticut Municipal Electric Energy Cooperative ("CMEEC") as a System Engineer. He was responsible for providing operational, financial, and rate expertise to Coop’s budgeting, ratemaking and system planning processes. He participated on behalf of CMEEC in the Hydro-Quebec/New England Power Pool Interconnection project and initiated the development of a database to support CMEEC's pool billing and financial data needs.

Prior to his CMEEC employment, he served as Chief Engineer at the South Norwalk (Connecticut) Electric Works, with responsibility for planning, data processing, engineering, rates and tariffs, generation and bulk power sales, and distribution operations. While at South Norwalk, he conceived and implemented, through Northeast Utilities and NEPOOL, a peak-shaving plan for South Norwalk and a neighboring municipal electric utility, which resulted in substantial power supply savings. He programmed and implemented a computer system to perform customer billing and maintain accounts receivable accounting. He also helped manage a generating station overhaul and the undergrounding of the distribution system in South Norwalk's downtown.

From 1977 to 1979, Mr. Lanzalotta worked as a public utility consultant for Van Scoyoc & Wiskup and separately for Whitman Requart & Associates in a variety of positions. During this time, he developed cost of service, rate base evaluation, and rate design impact data to support direct testimony and exhibits in a variety of utility proceedings, including utility price squeeze cases, gas pipeline rates, and wholesale electric rate cases.

Prior to that, He worked for approximately 2 years as a Service Tariffs Analyst for the Finance Division of the Baltimore Gas & Electric Company where he developed cost and revenue studies, evaluated alternative rate structures, and studied the rate structures of other utilities for a variety of applications. He was also employed by BG&E in Electric System Operations for approximately 3 years, where his duties included operations analysis, outage reporting, and participation in the development of BG&E's first computerized customer information and service order system.

Mr. Lanzalotta is a member of the Institute of Electrical & Electronic Engineers, the Association of Energy Engineers, the National Fire Protection Association, and the American Solar Energy Society. He is also registered Professional Engineer in the states of Maryland and Connecticut.

EXHIBIT PJL-2

Proceedings In Which
Peter J. Lanzalotta
Has Testified

1. **In re: Public Service Company of New Mexico**, Docket Nos. ER78-337 and ER78-338 before the Federal Energy Regulatory Commission, concerning the need for access to calculation methodology underlying filing.

2. **In re: Baltimore Gas and Electric Company**, Case No. 7238-V before the Maryland Public Service Commission, concerning outage replacement power costs.

3. **In re: Houston Lighting & Power Company**, Texas Public Utilities Commission Docket No. 4712, concerning modeling methods to determine rates to be paid to cogenerators and small power producers.

4. **In re: Nevada Power Company**, Nevada Public Service Commission, Docket No. 83-707 concerning rate case fuel inventories, rate base items, and O&M expense.

5. **In re: Virginia Electric & Power Company**, Virginia State Corporation Commission, Case No. PUE820091, concerning the operating and reliability-based need for additional transmission facilities.

6. **In re: Public Service Electric & Gas Company**, New Jersey Board of Public Utilities, Docket No. 831-25, concerning outage replacement power costs.

7. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. P-830453, concerning outage replacement power costs.

8. **In re: Cincinnati Gas & Electric Company**, Public Utilities Commission of Ohio, Case No. 83-33-EL-EFC, concerning the results of an operations/fuel-use audit conducted by Mr. Lanzalotta.

9. **In re: Kansas City Power and Light Company**, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

10. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. R-850152, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

11. **In re: ABC Method Proposed for Application to Public Service Company of Colorado**, before the Public Utilities Commission of the State of Colorado, on behalf of the Federal Executive Agencies ("FEA"), concerning a production cost allocation methodology proposed for use in Colorado.

12. **In re: Duquesne Light Company**, Docket No. R-870651, before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning the system reserve margin needed for reliable service.

13. **In re: Pennsylvania Power Company**, Docket No. I-7970318 before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning outage replacement power costs.

14. **In re: Commonwealth Edison Company**, Docket No. 87-0427 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from new base-load generating facilities, needed for reliable system operation.

15. **In re: Central Illinois Public Service Company**, Docket No. 88-0031 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the degree to which existing generating capacity is needed for reliable and/or economic system operation.

16. **In re: Illinois Power Company**, Docket No. 87-0695 before the State of Illinois Commerce Commission, on behalf of Citizens Utility Board of Illinois, Governors Office of Consumer Services, Office of Public Counsel and Small Business Utility Advocate, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

17. **In re: Florida Power Corporation**, Docket No. 860001-EI-G (Phase II), before the Florida Public Service Commission, on behalf of the Federal Executive Agencies of the United States, concerning an investigation into fuel supply relationships of Florida Power Corporation.

18. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Docket No. 877, on behalf of the Public Service Commission Staff, concerning the need for and availability of new generating facilities.

19. **In re: South Carolina Electric & Gas Company**, before the South Carolina Public Service Commission, Docket No. 88-681-E, On Behalf of the State of Carolina Department of Consumer Affairs, concerning the capacity needed for reliable system operation, the capacity available from existing generating units, relative jurisdictional rate of return, reconnection charges, and the provision of supplementary, backup, and maintenance services for QFs.

20. **In re: Commonwealth Edison Company**, Illinois Commerce Commission, Docket Nos. 87-0169, 87-0427, 88-0189, 88-0219, and 88-0253, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation.

21. **In re: Illinois Power Company**, Illinois Commerce Commission, Docket No. 89-0276, on behalf of the Citizen's Utility Board Of Illinois, concerning the determination of capacity available from existing generating units.

22. **In re: Jersey Central Power & Light Company**, New Jersey Board of Public Utilities, Docket No. EE88-121293, on behalf of the State of New Jersey Department of the Public Advocate, concerning evaluation of transmission planning.

23. **In re: Canal Electric Company**, before the Federal Energy Regulatory Commission, Docket No. ER90-245-000, on behalf of the Municipal Light Department of the Town of Belmont, Massachusetts, concerning the reasonableness of Seabrook Unit No. 1 Operating and Maintenance expense.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

24. **In re: New Hampshire Electric Cooperative Rate Plan Proposal**, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation.

25. **In re: Connecticut Light & Power Company**, before the Connecticut Department of Public Utility Control, Docket No. 90-04-14, on behalf of a group of Qualifying Facilities concerning O&M expenses payable by the QFs.

26. **In re: Duke Power Company**, before the South Carolina Public Service Commission, Docket No. 91-216-E, on behalf of the State of South Carolina Department of Consumer Advocate, concerning System Planning, Rate Design and Nuclear Decommissioning Fund issues.

27. **In re: Jersey Central Power & Light Company**, before the Federal Energy Regulatory Commission, Docket No. ER91-480-000, on behalf of the Boroughs of Butler, Madison, Lavallette, Pemberton and Seaside Heights, concerning the appropriateness of a separate rate class for a large wholesale customer.

28. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Formal Case No. 912, on behalf of the Staff of the Public Service Commission of the District of Columbia, concerning the Application of PEPCO for an increase in retail rates for the sale of electric energy.

29. **Commonwealth of Pennsylvania, House of Representatives**, General Assembly House Bill No. 2273. Oral testimony before the Committee on Conservation, concerning proposed Electromagnetic Field Exposure Avoidance Act.

30. **In re: Hearings on the 1990 Ontario Hydro Demand\Supply Plan**, before the Ontario Environmental Assessment Board, concerning Ontario Hydro's System Reliability Planning and Transmission Planning.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

31. **In re: Maui Electric Company**, Docket No. 7000, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning MECO's generation system, fuel and purchased power expense, depreciation, plant additions and retirements, contributions and advances.

32. **In re: Hawaiian Electric Company, Inc.**, Docket No. 7256, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning need for, design of, and routing of proposed transmission facilities.

33. **In re: Commonwealth Edison Company**, Docket No. 94-0065 before the Illinois Commerce Commission on behalf of the City of Chicago, concerning the capacity needed for system reliability.

34. **In re: Commonwealth Edison Company**, Docket No. 93-0216 before the Illinois Commerce Commission on behalf of the Citizens for Responsible Electric Power, concerning the need for proposed 138 kV transmission and substation facilities.

35. **In re: Commonwealth Edison Company**, Docket No. 92-0221 before the Illinois Commerce Commission on behalf of the Friends of Illinois Prairie Path, concerning the need for proposed 138 kV transmission and substation facilities.

36. **In re: Commonwealth Edison Company**, Docket No. 94-0179 before the Illinois Commerce Commission on behalf of the Friends of Sugar Ridge, concerning the need for proposed 138 kV transmission and substation facilities.

37. **In re: Public Service Company of Colorado**, Docket Nos. 95A-531EG and 95I-464E before the Colorado Public Utilities Commission on behalf of the Office of Consumer Counsel, concerning a proposed merger with Southwestern Public Service Company and a proposed performance-based rate-making plan.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

38. **In re: South Carolina Electric & Gas Company, Duke Power Company, and Carolina Power & Light Company**, Docket No. 95-1192-E, before the South Carolina Public Service Commission on behalf of the South Carolina Department of Consumer Advocate, concerning avoided cost rates payable to qualifying facilities.

39. **In re: Lawrence A. Baker v. Truckee Donner Public Utility District**, Case No. 55899, before the Superior Court of the State of California on behalf of Truckee Donner Public Utility District, concerning the reasonableness of electric rates.

40. **In re: Black Hills Power & Light Company**, Docket No. OA96-75-000, before the Federal Energy Regulatory Commission on behalf of the City of Gillette, Wyoming, concerning the Black Hills' proposed open access transmission tariff.

41. **In re: Metropolitan Edison Company and Pennsylvania Electric Company** for Approvals of the Restructuring Plan Under Section 2806, Docket Nos. R-00974008 and R-00974009 before the Pennsylvania PUC on behalf of Operating NUG Group, concerning miscellaneous restructuring issues.

42. **In re: New Jersey State Restructuring Proceeding** for consideration of proposals for retail competition under BPU Docket Nos. EX94120585U; E097070457; E097070460; E097070463; E097070466 before the New Jersey BPU on behalf of the New Jersey Division of Ratepayer Advocate, concerning load balancing, third party settlements, and market power.

43. **In re: Arbitration Proceeding In City of Chicago v. Commonwealth Edison** for consideration of claims that franchise agreement has been breached, Proceeding No. 51Y-114-350-96 before an arbitration panel board on behalf of the City of Chicago concerning electric system reliability.

44. **In re: Transalta Utilities Corporation**, Application No. RE 95081 on behalf of the ACD companies, before the Alberta Energy And Utilities Board in reference to the use and value of interruptible capacity.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

45. **In re: Consolidated Edison Company,** Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for a breach of contract to provide firm transmission service on a non-discriminatory basis.

46. **In re: ESBI Alberta Ltd.,** Application No. 990005 on behalf of the FIRM Customers, before the Alberta Energy And Utilities Board concerning the reasonableness of the cost of service plus management fee proposed for 1999 and 2000 by the transmission administrator.

47. **In re: South Carolina Electric & Gas Company,** Docket No. 2000-0170-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new and repowered generating units at the Urquhart generating station.

48. **In re: BGE,** Case No. 8837 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

49. **In re: PEPCO,** Case No. 8844 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

50. **In re: GenPower Anderson LLC,** Docket No. 2001-78-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the GenPower Anderson LLC generating station.

51. **In re: Pike County Light & Power Company,** Docket No. P-00011872, on behalf of Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Pike County request for a retail rate cap exception.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

52. **In re: Potomac Electric Power Company and Conectiv,** Case No. 8890, on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning the proposed merger of Potomac Electric Power Company and Conectiv.

53. **In re: South Carolina Electric & Gas Company,** Docket No. 2001-420-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the Jasper County generating station.

54. **In re: Connecticut Light & Power Company,** Docket No. 217 on behalf of the Towns of Bethel, Redding, Weston, and Wilton, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between Plumtree Substation, Bethel and Norwalk Substation, Norwalk.

55. **In re: The City of Vernon, California,** Docket No. EL02-103 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting calendar year 2001 transactions.

56. **In re: San Diego Gas & Electric Company et. al.,** Docket No. EL00-95-045 on behalf of the City of Vernon, California before the Federal Energy Regulatory Commission concerning refunds and other monies payable in the California wholesale energy markets.

57. **In re: The City of Vernon, California,** Docket No. EL03-31 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2002 transactions.

58. **In re: Jersey Central Power & Light Company,** Docket Nos. ER02080506, ER02080507, ER02030173, and EO02070417 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in

Proceedings In Which
Peter J. Lanzalotta
Has Testified

base tariff rates.

59. **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability rules, standards and indices.

60. **In re: Central Maine Power Company,** Docket No. 2002-665, on behalf of the Maine Public Advocate and the Town of York before the Maine Public Utilities Commission concerning a Request for Commission Investigation into the New CMP Transmission Line Proposal for Eliot, Kittery, and York.

61. **In re: Metropolitan Edison Company,** Docket No. C-20028394, on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission concerning the reliability service complaint of Robert Lawrence.

62. **In re: The California Independent System Operator Corporation,** Docket No. ER00-2019 *et al.* on behalf of the City of Vernon, California, before the Federal Energy Regulatory Commission concerning wholesale transmission tariffs, rates and rate structures proposed by the California ISO.

63. **In re: The Narragansett Electric Company,** Docket No. 3564 on behalf of the Rhode Island Department of Attorney General, before the Rhode Island Public Utilities Commission concerning the proposed relocation of the E-183 transmission line.

64. **In re: The City of Vernon, California,** Docket No. EL04-34 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2003 transactions.

65. **In re: Atlantic City Electric Company,** Docket No. ER03020110 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

66. **In re: Connecticut Light & Power Company and the United Illuminating Company,** Docket No. 272 on behalf of the Towns of Bethany, Cheshire, Durham, Easton, Fairfield, Hamden, Middlefield, Milford, North Haven, Norwalk, Orange, Wallingford, Weston, Westport, Wilton, and Woodbridge, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between the Scoville Rock Switching Station in Middletown and the Norwalk Substation in Norwalk, Connecticut.

67. **In re: Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company,** Docket No. I-00040102, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning electric service reliability performance.

68. **In re: Entergy Louisiana, Inc.,** Docket No. U-20925 RRF-2004 on behalf of Bayou Steel before the Louisiana Public Service Commission concerning a proposed increase in base rates.

69. **In re: Jersey Central Power & Light Company,** Docket No. ER02080506, Phase II, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

70. **In re: Maine Public Service Company,** Docket No. 2004-538, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 138 kV transmission line from Limestone, Maine to the Canadian border near Hamlin, Maine.

71. **In re: Pike County Light and Power Company,** Docket No. M-00991220F0002, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Company's Petition to amend benchmarks for distribution reliability.

72. **In re: Atlantic City Electric Company,** Docket No. EE04111374, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey

Proceedings In Which
Peter J. Lanzalotta
Has Testified

Board of Public Utilities concerning the need for transmission system reinforcement, and related issues.

73. **In re: Bangor Hydro-Electric Company,** Docket No. 2004-771, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 345 kV transmission line from Orrington, Maine to the Canadian border near Baileyville, Maine.

74. **In re: Eastern Maine Electric Cooperatve,** Docket No. 2005-17, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a petition to approve a purchase of transmission capacity on a 345 kV transmission line from Maine to the Canadian province of New Brunswick.

75. **In re: Virginia Electric and Power Company,** Case No. PUE-2005-00018, on behalf of the Town of Leesburg VA and Loudoun County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for transmission and substation facilities in Loudoun County.

76. **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability reporting, standards, and indices.

77. **In re: Proposed Merger Involving Constellation Energy Group Inc. and the FPL Group, Inc.**, Case No. 9054, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the proposed merger involving Baltimore Gas & Electric Company and Florida Light & Power Company.

78. **In re: Proposed Sale and Transfer of Electric Franchise of the Town of St. Michaels to Choptank Electric Cooperative, Inc.,** Case No. 9071, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the sale by St. Michaels of their electric franchise and service area to Choptank.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

79. **In re: Petition of Rockland Electric Company for the Approval of Changes in Electric Rates, and Other Relief,** BPU Docket No. ER06060483, on behalf of the Department of the Public Advocate, Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning electric service reliability and reliability-related spending.

80. **In re: The Complaint of the County of Pike v. Pike County Light & Power Company, Inc.,** Docket No. C-20065942, et al., on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, concerning electric service reliability and interconnecting with the PJM ISO.

81. **In re: Application of American Transmission Company to Construct a New Transmission Line,** Docket No. 137-CE-139, on behalf of The Sierra Club of Wisconsin, before the Public Service Commission of Wisconsin, concerning the request to build a new 138 kV transmission line.

82. **In re: The Matter of the Self-Complaint of Columbus Southern Power Company and Ohio Power Company Regarding the Implementation of Programs to Enhance Distribution Service Reliability,** Case No. 06-222-EL-SLF, on behalf of The Office of The Ohio Consumers' Counsel, before the Public Utilities Commission of Ohio, concerning distribution system reliability and related topics.

83. **In re: Central Maine Power Company,** Docket No. 2006-487, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning CMP's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line between Saco and Old Orchard Beach.

84. **In re: Bangor Hydro Electric Company,** Docket No. 2006-686, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning BHE's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line and substation in Hancock County.

85. **In re: Commission Staff's Petition For Designation of Competitive Renewable Energy Zones,** Docket No. 33672, on behalf of the Texas Office

Proceedings In Which
Peter J. Lanzalotta
Has Testified

of Public Utility Counsel, concerning the Staff's Petition and the determination of what areas should be designated as CREZs by the Commission.

86. **In re: Virginia Electric and Power Company,** Case No. PUE-2006-00091, on behalf of the Towering Concerns and Stafford County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Stafford County.

87. **In re: Trans-Allegheny Interstate Line Company,** Docket Nos. A-110172 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Pennsylvania.

88. **In re: Commonwealth Edison Company,** Docket No. 07-0566, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning electric transmission and distribution projects promoted as smart grid projects, and the rider proposed to pay for them.

89. **In re: Commonwealth Edison Company,** Docket No. 07-0491, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning the applicability of electric service interruption provisions.

90. **In re: Hydro One Networks ,** Case No. EB-2007-0050, on behalf of Pollution Probe, before the Ontario Energy Board, concerning a request for leave to construct electric transmission facilities in the Province of Ontario.

91. **In re: PEPCO Holdings, Inc.,** Docket No. ER-08-686-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

92. **In re: PPL Electric Utilities Corporation and Public Service Electric and Gas Company,** Docket No. ER-08-23-000, on behalf of the Joint Consumer Advocates, including the state consumer advocacy offices for the States of

Proceedings In Which
Peter J. Lanzalotta
Has Testified

Maryland, West Virginia, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

93. **In re: PPL Electric Utilities Corporation,** Docket Nos. A-2008-2022941 and P-2008-2038262, on behalf of Springfield Township, Bucks County, PA, before the Pennsylvania Public Utility Commission, concerning the need for and alternatives to proposed electric transmission lines and a proposed electric substation.

94. **In re: PEPCO Holdings, Inc.,** Docket No. ER08-1423-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

95. **In re: Public Service Electric and Gas Company, Inc.,** Docket No. ER09-249-000, on behalf of the New Jersey Division of Rate Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

96. **In re: New York Regional Interconnect Inc.,** Case No. 06-T-0650, on behalf of the Citizens Against Regional Interconnect, before the New York Public Service Commission, concerning the economics of and alternatives to proposed transmission facilities.

97. **In re: Central Maine Power Company and Public Service of New Hampshire,** Docket No. 2008-255, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning CMP's and PSNH's Petition for Finding of Public Convenience & Necessity to build the Maine Power Reliability Project, a series of new and rebuilt electric transmission facilities to operate at 345 kV and 115 kV in Maine and New Hampshire.

98. **In re: PPL Electric Utilities Corporation, Docket No. A-2009-2082652 et al,** on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning the Company's application for approval to site and construct electric transmission facilities in Pennsylvania.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

99. **In re: Bangor Hydro-Electric,** Docket No. 2009-26, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning BHE's Petition for Certificate of Public Convenience & Necessity to build a 115 kV transmission line in Washington and Hancock Counties.

100. **In re: United States, et al. v. Cinergy Corp., et al.** Civil Action No. IP99-1693 C-M/S, on behalf of Plaintiff United States and Plaintiff-Intervenors State of New York, State of New Jersey, State of Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, before the United States District Court for the Southern District of Indiana, concerning the system reliability impacts of the potential retirement of Gallagher Power Station Unit 1 and Unit 3.

101. **In re: Application of Potomac Electric Power Company, et al.** Case No. 9179, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the application for a determination of need under a certificate of public convenience and necessity for the Maryland portion of the MAPP transmission line, and related facilities.

102. **In re: Potomac Electric Power Company v. Perini/Tompkins Joint Venture,** Case No. 9210, on behalf of Perini Tompkins before the Maryland Public Service Commission concerning a review of PEPCO's estimates of electric consumption by Perini Tompkins Joint Venture's temporary electric service at National Harbor during a 29 month period for which no metered consumption data is available.

103. **In re: Duke Energy Ohio, Inc.,** Case No. 10-503-EL-FOR, on behalf of the Natural Resources Defense Council and Sierra Club before the Public Utilities Commission Of Ohio, concerning a review of the reliability impacts that would result from closure of selected generating units as part of a review of Duke's 2010 Electric Long-Term Forecast Report and Resources Plan.

104. **In re: Detroit Edison Company,** Case Nos. U-16472 and 16489, on behalf of the Michigan Environmental Council and the Natural Resources Defense Council, before the Michigan Public Service Commission, concerning a review looking for studies of the reliability impacts that would result from closure of selected generating units as part of an electric rate increase case.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

105. **In re: Potomac Electric Power Company,** Case No. 9240, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability performance.

106. **In re: ISO New England, Inc.,** Docket No. ER12-991-000, on behalf of the Conservation Law Foundation, before the Federal Energy Regulatory Commission, concerning proposals for procedures for obtaining temporary reliability-based relief from complying with newly instituted environmental regulations addressing emissions from electric generating facilities.

107. **In re: Western Massachusetts Electric Company, Docket No. D.P.U. 11-119-C** on behalf of the Attorney General of the Commonwealth of Massachusetts, before the Massachusetts Department of Public Utilities, concerning storm preparation, performance, and restoration of electric service.

108. **In re: Delmarva Power & Light Company,** Case No. 9285, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning storm restoration expenses and tree trimming expenses as part of a base rate increase case.

109. **In re: Potomac Electric Power Company,** Case No. 9286, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning storm restoration expenses and tree trimming expenses as part of a base rate increase case.