STATE OF IOWA
DEPARTMENT OF COMMERCE
BEFORE THE IOWA UTILITIES BOARD

Application of Interstate Power and Light Company, for Authority to Revise Electric Rates	))))	**Docket No. RPU-2019-0001** **(TF-2019-0017, TF-2019-0018)**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

SIERRA CLUB

PUBLIC VERSION

Resource Insight, Inc.

AUGUST 1, 2019

TABLE OF CONTENTS

TABLE OF EXHIBITS

Confidential Exhibit SC-10	IPL's Confidential Response to Sierra Club Information Request 1-SC-14 and Confidential Attachment A
Confidential Exhibit SC-11	IPL's Confidential Response to Sierra Club Information Request 4-SC-1
Confidential Exhibit SC-12	IPL's Confidential Response to Sierra Club Information Request 1-SC-07
Confidential Exhibit SC-13	IPL's Confidential Response to Sierra Club Information Request 4-SC-2
Confidential Exhibit SC-14	IPL's Confidential Response to Sierra Club Information Request 1-SC-17, Confidential Attachment A
Confidential Exhibit SC-15	IBEC-1, Confidential Attachment C Kitchen, RPU-2016-0005
Confidential Exhibit SC-16	IPL's Confidential Response to IBEC 65, RPU-2016-0005
Confidential Exhibit SC-17	IPL's Confidential Response to IBEC 61, Confidential Attachment B, RPU-2016-0005
Confidential Exhibit SC-18	IPL's Confidential Response to Sierra Club Information Request 1-SC-09
Exhibit SC-19	Bloomberg Study
Exhibit SC-20	Brattle Group Study

I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Incorporated, 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight since 1990. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plants under construction, ratemaking for excess and/or uneconomical plants entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Chernick Direct Ex. SC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included many reviews of the economics of power plants, utility planning, marginal costs, and related issues.

Q: On whose behalf have you worked?

A: A large percentage of my testimony has been filed on behalf of consumer advocates (e.g., the Massachusetts, New Mexico, Washington, and Illinois Attorney Generals; other official public consumer advocates in Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, Pennsylvania, Illinois, Minnesota, Maryland, Ohio, Vermont, Indiana, South Carolina, Arizona, West Virginia, Utah, District of Columbia, and Nova Scotia; and such non-profit consumer advocates as AARP, East Texas Legal Services, Public Interest Research Groups, Alliance for Affordable Energy, citizens' groups, Ontario School Energy Group, Citizens Action Coalition, and Small Business Utility Advocates). I have also worked for regulatory bodies in Massachusetts, Connecticut, District of Columbia, and Puerto Rico, as well as the Vermont House of Representatives.

The remainder of my clients include investor-owned and municipal utilities, municipalities (New York City, Chicago, Cincinnati, several

Massachusetts, New Hampshire and New York towns in various proceedings), large customers, power-plant developers and owners, labor unions, energy advocates and environmental groups.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Sierra Club.

Q: What is the scope of your testimony?

A: I review the economics of the coal plants owned (entirely or partly) by Interstate Power and Light ("IPL" or "the Company"), which is the applicant in the two proceedings in which this testimony is filed. My purpose is to determine whether continued operational and capital expenditures to run IPL's coal plants are prudent, as well as whether the plants remain economically used and useful for consumers.

My testimony relies on numerous IPL documents and discovery responses, including the testimony of IPL witnesses Brent R. Kitchen, Zachary D. Fields and Matthew. P. Cole, as well as publicly available documents from IPL, the Federal Energy Regulatory Commission, the Energy Information Administration, the Mid-Continent Independent System Operator (MISO) and the US Environmental Protection Agency (EPA). The confidential and non-confidential discovery responses that I cited are attached as exhibits.

Q: Why do you focus your testimony on the Company's coal units?

A: Nationally, coal plant economics have eroded due to the declining gas prices and renewable energy costs. Keeping the existing coal units in service is relatively expensive. Economic operation of coal units is heavily dependent on having a large number of hours in which market prices are higher than the costs of fuel and other operating costs for starting the units and generating electricity. Because coal units general take a long time to start up, change output, or restart after shutdown, those profitable hours also need to be predictable days in advance and must occur in clusters long enough to pay for the costs of cycling the unit up and down. The addition of large amounts of wind regionally has reduced the profitability of coal plants more than most other types of generation, because the coal plants often cannot run in the remaining hours of high net demand on the fossil-fueled system (total load minus renewable output) and market prices, unless they also run at times of low demand and low energy prices.

Q: Have you previously reviewed the economics of any of IPL's coal resources?

A: Yes. I examined the economics of MidAmerican's coal plants, including the four units jointly owned with IPL, as part of the MidAmerican Wind XII docket, *In Re Application of MidAmerican Energy Company for Determination of Ratemaking Principles*, Docket No. RPU-2018-0003. In that testimony, I found that: "The costs of fuel, operating and maintenance (O&M), overheads, and ongoing capital additions for most of the units, and particularly Ottumwa and Neal 3, appear to exceed the market value of their output." (Chernick Direct Testimony, RPU-2018-0003, filed August 3, 2018, pp. 4–5.) In that proceeding, the Board stated that rate cases are the appropriate place to examine coal plant economics.[1] The economics of IPL's coal units and of those units in which it has an ownership interest is therefore the focus of my testimony in this proceeding.

Q: What information did the Company provide in its Application relevant to determining whether its existing generation remains used and useful?

A: For the most part, the Application did not address the critical issue of whether IPL's generating resources supply electricity at the lowest reasonable cost.

IPL says that it "is continuing to transition its generating fleet to clean, more cost-effective sources of energy and capacity" (IPL Cole Direct Testimony at 2:19-22), but does not discuss the economics of its large existing coal-fired generating fleet. Mr. Cole's testimony does state:

> IPL is evaluating its generating fleet as a whole as part of its resource planning process. That includes, by way of example, an evaluation of the long-term role for Lansing Unit 4.... IPL is mindful of significant near-term investments that will be necessary to continue to operate Lansing Unit 4 in compliance with environmental requirements and, as with any generating units, will keep the long-term customer costs and benefits of Lansing Unit 4 in focus as it completes this analysis. Therefore, as part of its resource planning process, IPL is in the process of evaluating the role of Lansing Unit 4 in IPL's capacity portfolio and IPL's ability to serve its customers with an adequate supply of safe, reliable, and cost-effective energy and capacity.

Cole Direct Testimony at 8:5-17.

[1] Final Decision and Order, RPU-2018-0003, at 34 (December 4, 2018) ("[S]hould a rate-regulated utility continue to utilize an uneconomic facility, the Board may disapprove the costs incurred as imprudent or unreasonable during a rate case.").

Nonetheless, IPL's filing did not provide any details on this "resource planning process" that it is apparently undertaking, or what costs and benefits it is considering as part of this planning process.

Q: What coal-fired generation resources does IPL own?

A: As summarized in Table 1, IPL owns all or parts of seven coal plants. Two of these plants will be retired or converted to natural gas under a July 2015 consent decree with the U.S. government and the State of Iowa[2]:

- Burlington Unit 1 will be retired (or converted to burn natural gas) by December 31, 2021.
- Prairie Creek cogenerates electricity and sells steam, with most of the fuel energy going to the steam load. Under the July 2015 consent decree, Prairie Creek 4 was required to retire or refuel by June 1, 2018 (it converted to burn gas in 2017), and the small Prairie Creek units 1, 2 and 3 must retire or convert by December 31, 2025. Boilers 1 and 2 are limited to operating when needed by steam load starting in 2021.[3]

In some of the tables and figures below, I include Burlington or Prairie Creek units for comparative purposes.

[2] United States v. Interstate Power and Light Co., Civil Action No. C15-0061, Consent Decree, July 15, 2015, summary publicly available at https://www.epa.gov/enforcement/interstate-power-and-light-company-clean-air-act-settlement and consent decree available at https://www.epa.gov/sites/production/files/2015-07/documents/interstatepowerandlight-cd.pdf.

[3] From the boiler and generator data in the EIA Form 923 reports, boilers 1 and 2 apparently serve generator 1.

Table 1: Operating and Recently Converted Coal Plants

Plant	Unit(s)	Year Installed[a]	Retirement Year	Summer Capacity (MW)[b]	Operator	IPL Share Percent[c]	IPL Share MW[d]
Burlington	1	1968	2021	210.5	IPL	100%	210.5
George Neal	3	1975		510	MidAm	28%	142.8
George Neal	4	1978		644	MidAm	25.7%	165.5
Lansing	4	1977		248.3	IPL	100%	248.3
Louisa	1	1983		743.9	MidAm	4%	29.8
Ottumwa	1	1981		718.2	IPL	48%	344.7
Prairie Creek	1,3	1958	2021	30.3	IPL	100%	30.3
Prairie Creek	4	1967	Gas conv 2017	112.1	IPL	100%	112.1

Data sources:
[a] 2018 FERC Form 1, p. 402
[b] 2017 EIA 860
[c] 2017 EIA 860, Owner file
[d] Percent times Capacity
[e] EIA 923, Generator file

Q: Who owns the remainder of the jointly-owned plants?

A: Table 2 summarizes the ownership shares.

Table 2: Co-owners of IPL Coal Plants

Plant	Unit(s)	IPL	MidAm	Northwest Energy	Public Utilities
Neal	3	28%	72%		
Neal	4	25.7%	40.57%	8.68%	25.05%
Louisa	1	4%	88%		8%
Ottumwa	1	48%	52%		

Q: How are the IPL units dispatched?

A: The IPL units sell all their output to the MISO market and IPL purchases all energy required for load from MISO. The amount and timing of IPL generation differs from the energy needs of its customers. If a power plant produces one less MWh in an hour, IPL loses revenues equal to the locational market price (LMP) at that plant in that hour, and saves some costs of operating the plant. If IPL customers demand one more MWh, IPL will buy one more MWh from MISO. MISO may increase output to meet that load at an IPL plant, or at many other generators. Thus, the market value of the power plants and the market costs of serving customers are distinct.

Q: How does IPL take economics into account in deciding whether to retire its fossil plants?

A: IPL says that it takes economics into account in addressing retirement decisions:

> …IPL is continually engaged in ongoing evaluations of its generation fleet and the economic value provided by that fleet to its customers. Confidential Attachments A and B contain IPL's current generation planning assumptions and analysis regarding its generation fleet, which are subject to change, and do not represent a final decision by IPL as to the continued operation or retirement of any specific generation units.

IR 1-SC-24 Supplemental Confidential (Chernick Dir. Confidential Ex. SC-3).

Indeed, IPL provided two data responses showing economic analyses of decisions to retire or retain certain coal plants.[4] However, IPL does not appear to have conducted any analysis of the economics of continued operation of most of its remaining coal units, or to have updated past analyses as market prices have fallen.

[4] IR 1-SC-24 Supplemental Confidential and attachments (Chernick Dir. Confidential Ex. SC-3) and IR 1-SC-22 Confidential and attachments (Chernick Dir. Confidential Ex. SC-4). IPL describes the confidential attachments to its Response to IR 1-SC-22 as related to an "analysis of the economics of the continued operation on the Ottumwa Generating Station in docket EPB-2016-0150." Since the attachments are confidential, I will discuss those in detail in the later confidential Section IV.

A. Summary of Results

Q: What do you conclude from your analysis?

A: Based on the public cost and revenue data, as described in Section III, I find that all of IPL's major coal resources are uneconomic, have been uneconomic for several years, and are likely to remain uneconomic, compared to market prices and renewable resources. The worst performers are Ottumwa and the two Neal units.

Q: Does it appear that continued operation of any of the IPL coal resources are beneficial to ratepayers?

A: No. The costs of fuel, operating and maintenance (O&M), overheads, and capital additions for the units have exceeded the market value of their output. Those costs and market values are unlikely to fall enough to eliminate the operating losses of the coal units. All the remaining coal plants are facing additional investments to meet environmental requirements, as well as other periodic equipment addition and replacements, which further reduce the likelihood that the units will be economic.

Q: Once IPL has committed to operate the coal units for a year (or other lengthy period), is it economic to dispatch them?

A: Yes. Ideally, each unit would be dispatched in each hour in which the market energy price exceeds the unit's fuel and variable O&M. Looking at only these short-run marginal costs (without fixed O&M or continuing capital investments), each of the coal plants is economic to run in some hours, as I detail in Table 15. But the resources cannot be dispatched only in those hours, as I explain below (see page 33), reducing or eliminating the achievable energy benefits of running the units. And the fixed O&M, overheads, and capital additions needed to keep the coal plants running swamp the modest dispatch benefits.

Q: If the units are uneconomic, why are they still running?

A: There are three ways in which IPL may have kept the plants running at relatively high capacity factors. First, rather than bidding its coal units into the market as resources to be dispatched economically, IPL may have designated various of its coal units as "self-scheduled" or "must-run" units, ensuring that MISO will dispatch them, regardless of cost or price.

Second, when IPL bids the units into the MISO energy market, it may bid them in at prices below their short-run marginal costs of fuel and variable O&M.

Third, the coal units incur costs, including fixed O&M and capital additions, that would not be included in the hourly energy market bids, but need to be covered by the profit in the market. If IPL ignores the fixed annual O&M and investment costs, it would find many hours in which the units are worth running, considering only the hourly fuel and variable O&M. A generator can make money in many hours but still lose money over the year.

The first two mechanisms represent situations in which IPL could force the coal units to run when they are not economic sources of energy for the region. Merchant generation owners usually do not engage in that behavior, since they would lose money on every megawatt-hour sold. Vertically-integrated utilities, on the other hand, can often count on recovering those losses from their retail (and in some cases, regulated wholesale) customers. I do not fully understand the incentives that would encourage IPL (and its co-owners) to run the coal plants uneconomically, but the Company may be motivated by an interest in avoiding scrutiny of the coal plants' economics until more of their costs have been depreciated.

The third mechanism results from the difference between short-run (hourly or daily) costs and annual costs. Even a unit that can dispatch at costs below the market price in every hour (e.g., a hydro or nuclear plant), covering its variable costs by a wide margin, may not cover its fixed O&M, capital additions, and other forward-going costs. Many merchant power plants (including some nuclear plants, which have short-run costs below market energy prices in almost all hours) have retired due to the inability to cover their forward-going costs. Over time, the most expensive plants should be replaced by less-expensive resources.

Since IPL is not subject to market discipline, as it would be if it were a merchant generator, that role falls to the Commission.

Q: If the coal plants are shut down, what resources would replace them?

A: Most of my analysis compares the cost of running the plants to the prices of market energy and capacity, whether sold by the plants to MISO or purchased to replace retired units. New wind resources are also less expensive than continuing to run the coal plants; energy from utility-scale solar plants is also comparable to the cost of the coal resources, while providing more energy in the high-value peak hours. I discuss replacement options further in Section V, below.

Q: Do your estimates of the costs the coal units include recovery of the previous investment in those resources?

A: No. I compare the going-forward costs of the plants with the costs of replacing their energy and capacity. The total costs of the coal units is higher than those going-forward costs.

Q: Do your conclusions rely on any specific assumptions about the recovery of the unamortized capital cost of the retired plants?

A: No. I do not include any sunk capital costs in my analysis. My conclusion is that ratepayers are losing money on the continued operation of the plants. Customers would be better off with retirement of the plants, even if they continue to pay for depreciation and return on the sunk costs, just as if the plants were in service. IPL can be made whole, and ratepayer costs can be reduced, if the unamortized investment can be securitized and refinanced at a lower cost of capital.

As discussed further below, the Board has many ratemaking options, including disallowing recovery of future investment and O&M commitments made after IPL should have been clear that continued operation is uneconomic.

Q: And are these conclusions confirmed by IPL's confidential data?

A: Yes. The limited analyses of plant economics that IPL has provided confidentially reinforce my conclusion, as discussed in Section IV.B. Most importantly, IPL's own studies of the economics of [redacted]

As discussed in Sections IV.A and IV.C, the other confidential historical and projected data provided by IPL also confirms that the values I derived from public sources are reasonable or favorable to IPL, in terms of the costs and benefits of operating IPL's coal plants. My conclusions regarding the economics of IPL's coal plants are thus conservative.

B. Recommendations

Q: What are your recommendations?

A: IPL should plan for the retirement of all its coal resources, timed to minimize the losses of continued operation and to avoid any major capital expenditures.[5] Ottumwa and Neal 3 and 4 look particularly uneconomic, but Lansing should also be retired as soon as feasible. While Louisa is uneconomic, and IPL should press MidAmerican to minimize the continued cost of running the plant, it appears to be the least uneconomic of IPL's coal resources.

In support of the retirement of these units, IPL should start (in conjunction with MidAmerican for the jointly-owned units) the process of determining how transmission constraints, reliability, or other considerations will shape IPL's choice and location of replacement resources. IPL should also be thinking about the cost-recovery timing and ratemaking for the retiring units, so that customers are not excessively burdened by recovery of prudently-incurred costs, especially as IPL is recovering the front-loaded costs of recent ratebase additions.

To replace these retiring coal plants, IPL should be procuring a mix of market purchases, wind, and central and distributed solar and storage, as well as improving customer end-use efficiency and encouraging demand-response

[5] Burlington and the Prairie Creek units are already required to retire or convert to gas.

resources that allow IPL to shift load out of hours with high loads, low regional wind and solar production, and high costs. In selecting the replacement resources, IPL should strive to minimize ratepayer costs and risks. Where a resource type can be developed and/or owned by both IPL and third parties, IPL should compare the costs of building the resources itself; contracting for a third party to build and operate the resources, eventually transferring ownership to IPL; and conventional power-purchase agreements (PPAs), in which the third party builds, owns and operates the facility. The least-cost and least-risk option may vary among projects.

Q: Do you have any recommendations for the Board?

A: Yes. The Board should find that IPL would be imprudent to continue incurring avoidable future capital and operating costs for its coal resources and that the resulting costs would not be in the public interest. The Board should put IPL on notice that it will disallow cost recovery for such discretionary future expenditures.[6] Finally, Board should support reasonable efforts that IPL undertakes to prepare for the retirement of the uneconomic units.

III. Public Data on IPL Coal Units' Performance, Costs and Revenues

Q: What public performance, cost and revenue components of the IPL coal units have you reviewed?

[6] Discretionary and avoidable spending would include capital additions (including environmental retrofits) necessary to continue operate the units, as opposed to costs required to remediate existing safety and environmental problems.

A: I have compiled performance data on unit capacity factor, forced outage rate, availability and heat rate. I have also assembled cost data for fuel, variable O&M, fixed O&M, overheads, and capital additions. For revenues, I combined EPA data on hourly generation with MISO-reported energy prices, as well as annual MISO capacity prices, the installed capacity of each IPL coal unit, and the MISO forced-outage rate for plants of the size of the IPL unit.

A. Performance Measures

Q: Which performance measures have you compiled for the IPL coal units?

A: Table 3 shows data on each coal unit's 2018 capacity factor, 2018 heat rate, and the average rate that MISO reports for coal units of the size of each of the IPL units.

Table 3: Coal Plant Technical Performance

Plant	Unit	2018 Capacity Factor[a]	2018 Heat Rate[b] (Btu/kWh)	Forced Outage and Deration Rate (MISO)
Burlington	1	65%	10,544	9.82%
Neal North	3	51%	10,293	9.28%
Neal South	4	55%	10,338	8.22%
Lansing	4	41%	11,590	9.82%
Louisa	1	75%	10,570	8.22%
Ottumwa	1	59%	10,260	8.22%
Prairie Creek	1,3	30%	14,513	4.60%

Notes: [a] *From EIA 860 and 923. www.eia.gov/survey/#eia-860 www.eia.gov/survey/#eia-923*

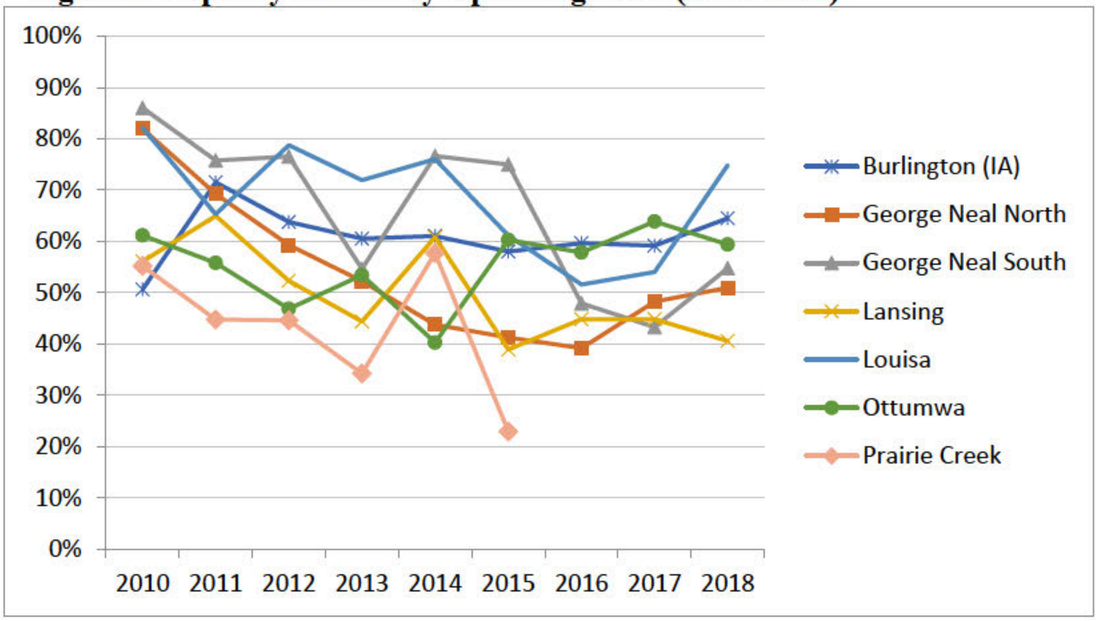
[b] *2018 EIA Form 923.*

[c] *"Planning Year 2019–2020 Loss of Load Expectation Study Report," Loss of Load Expectation Working Group, October 17, 2018, Table 4-1. https://cdn.misoenergy.org/2019%20LOLE%20Study%20Report285051.pdf*

Q: How has coal utilization changed over the past five years?

A: Figure 1 depicts annual capacity factors by unit for the last nine years, from EIA forms 860 and 923.

Figure 1: Capacity Factors by Operating Plant (2010–2018)[7]



In 2010, the fleet wide coal unit capacity factor was 63%; that had dropped to 48% by 2016. Following the end of coal consumption at Prairie Creek 4 (which generally operated at a below-average capacity factor), the average rose to 54% in 2018. Overall, IPL is generating about 22% less energy from its coal fleet than eight years earlier.

B. Fuel and O&M

Q: What public information do you have on the fuel and O&M costs of IPL's coal units?

A: I have the following public data on O&M:

- the fuel and O&M cost data that MidAmerican, IP&L and NorthWestern file in the 2012–2018 FERC Form 1 reports for each unit, and

[7] EIA forms 860 and 923. See notes to Table 3.

- variable O&M estimates by unit from the Bloomberg New Energy Finance (BNEF).

Table 4 provides data on the fuel and total nonfuel O&M costs for each of the coal units, in dollars per megawatt-hour, from IPL FERC Form 1 reports for those years, pages 402 and 403. The FERC Form data from MidAmerican and Northwestern will be used in the computation of overhead expenses, as described in Section III.D.

Table 4: Fuel and Non-Fuel O&M Costs by Coal Plant ($/MWh)

		2012	2013	2014	2015	2016	2017	2018
Burlington	Fuel	$17.19	$18.15	$14.85	$16.43	$16.64	$17.56	$17.61
	NF O&M	$4.07	$4.57	$4.87	$5.62	$5.86	$6.13	$5.02
	Total	$21.26	$22.73	$19.72	$22.05	$22.51	$23.69	$22.63
Neal 3	Fuel	$15.91	$19.14	$20.34	$20.41	$19.85	$19.88	$18.91
	NF O&M	$6.54	$8.03	$17.23	$12.37	$12.52	$12.80	$18.23
	Total	$22.44	$27.17	$37.57	$32.77	$32.37	$32.67	$37.13
Neal 4	Fuel	$15.39	$18.73	$19.71	$18.95	$18.41	$20.89	$18.42
	NF O&M	$4.71	$12.17	$6.55	$6.56	$10.20	$10.70	$9.23
	Total	$20.09	$30.90	$26.26	$25.51	$28.61	$31.58	$27.65
Lansing 4	Fuel	$29.97	$30.55	$30.99	$32.08	$32.21	$31.00	$28.40
	NF O&M	$5.60	$6.88	$6.80	$9.71	$9.29	$8.47	$8.85
	Total	$35.57	$37.43	$37.79	$41.80	$41.50	$39.47	$37.26
Louisa	Fuel	$16.14	$17.12	$18.32	$19.44	$18.68	$19.62	$17.57
	NF O&M	$5.45	$8.85	$5.95	$6.67	$7.48	$12.34	$6.35
	Total	$21.59	$25.97	$24.27	$26.11	$26.16	$31.96	$23.92
Ottumwa	Fuel	$22.23	$22.02	$20.93	$19.96	$19.55	$19.43	$21.07
	NF O&M	$3.82	$3.77	$6.41	$4.09	$4.51	$4.12	$4.47
	Total	$26.05	$25.79	$27.34	$24.05	$24.07	$23.55	$25.54
Prairie Creek 4	Fuel	$35.19	$39.89	$32.29	$40.08	$43.49	$38.27	
	NF O&M	$12.03	$19.56	$12.22	$29.27	$37.15	$33.47	
	Total	$47.22	$59.45	$44.51	$69.35	$80.64	$71.74	

C. Capital Additions

Q: What information do you have regarding the ongoing capital costs for the IPL coal plants?

A: I have compiled the historical additions to capital plant in service for the IPL plants from the IPL FERC Form 1 reports for 2012–2018. The capital additions are computed from the change in capital cost reported in the annual FERC Form 1 reports.[8] These are net additions, representing the investment at the plant in the particular year, minus the cost of equipment at that plant retired. Thus, net additions understate the costs imposed on ratepayers. In fact, in some years, the retirements can exceed additions, resulting in negative net additions.[9]

Q: What have been the historical net capital additions for the IPL units?

A: Table 5 lists the net annual capital additions by unit. Where the capital cost declined from year to year, I left the line blank.

[8] I eliminated the line for "Asset Retirement Costs," which are accounting allowances for future removal costs.

[9] The interim retirements do not generally reduce revenue requirements. The cost of the retired equipment is removed from rate base, but the utility offsets that reduction in ratebase by removed an equal amount from the accumulated depreciation account. Since a plant's contribution to rate base equals plant-in-service minus accumulated depreciation, removing the same amount from plant and accumulated depreciation leaves rate base unchanged.

Table 5: IPL Net Capital Additions ($ millions)

	2013	2014	2015	2016	2017	2018
Burlington	$5.23	$13.34	$1.75	$5.89	$2.96	$0.68
Neal 3		$75.73	$4.03	$1.77	$0.39	$6.13
Neal 4	$82.72	$2.93	$0.97	$0.89	$1.41	
Lansing 4	$1.13	$1.94	$65.13	$0.96	$10.55	$0.02
Louisa	$0.16	$0.14	$0.21	$0.06	$0.99	$1.38
Ottumwa	$7.58	$241.84		$8.14	$13.37	$5.66
Prairie Creek 1,3	$4.90	$5.89	$0.59		$0.37	$1.08
Prairie Creek 4	$8.79	$4.47	$3.41	$3.24	$1.05	

The capital additions to Ottumwa in 2014 and Lansing in 2015 resulted from the addition of scrubbers and baghouses; the large additions at Neal 3 in 2014 and Neal 4 in 2013 were similarly associated with scrubbers, baghouses, NOx controls, and other emissions equipment. While the plants face further environmental retrofits, these are not routine costs. Thus, I exclude them from the average costs below.

In Table 6, I convert those capital additions to $/kW by dividing by IPL's ownership share of the unit, as well as the average capital additions over the last six years. Since these values are net of retirements, they understate the actual costs to ratepayers.

Table 6: IPL Net Capital Additions ($/kW)

	2013	2014	2015	2016	2017	2018	Average	Without Outliers
Burlington	$24.83	$63.36	$8.29	$27.99	$14.05	$3.21	$23.62	$23.62
Neal 3		$148.50	$7.90	$3.47	$0.77	$12.01	$34.53	$6.04
Neal 4	$128.45	$4.56	$1.51	$1.38	$2.19		$27.62	$2.41
Lansing 4	$4.54	$7.82	$262.31	$3.88	$42.48	$0.09	$53.52	$11.76
Louisa	$0.21	$0.19	$0.29	$0.08	$1.33	$1.86	$0.66	$0.66
Ottumwa	$10.56	$336.73		$11.34	$18.62	$7.88	$77.03	$12.10
Prairie Creek 1,3	$161.82	$194.25	$19.56		$12.10	$35.68	$84.68	
Prairie Creek 4	$78.43	$39.85	$30.38	$28.91	$9.33		$37.38	

Some of these additions (Ottumwa and Neal #3 in 2014, Neal #4 in 2013, Lansing 4 in 2015) represent major environmental retrofits, which may not recur at the same level for many years, but most of the costs appear to be for smaller routine replacements and upgrades. Table 7 below features the same information shown in Table 6 but converted to dollars per MWh.

Table 7: IPL Net Capital Additions ($/MWh)

	2013	2014	2015	2016	2017	2018	Average	Excluding Outliers
Burlington	$4.65	$11.88	$1.61	$5.30	$2.71	$0.57	$4.45	
Neal 3		$135.09	$8.22	$3.49	$0.65	$9.53	$31.40	$5.47
Neal 4	$102.14	$2.59	$0.92	$1.29	$2.20		$21.83	$1.75
Lansing 4	$1.16	$1.46	$75.94	$1.07	$10.82	$0.02	$15.08	$2.91
Louisa	$0.81	$0.70	$1.25	$0.44	$6.91	$7.02	$2.85	
Ottumwa	$4.35	$183.70		$4.13	$6.64	$2.97	$40.36	$4.52
Prairie Creek 1,3	$49.86	$56.17	$9.45		$5.72	$13.71	$26.98	
Prairie Creek 4	$24.50	$7.46	$13.87	$13.69	$4.05		$12.71	

Q: Did IPL provide any data on historical capital additions by coal plant in this proceeding?

A: No. Sierra Club asked for the annual "Capital expenditures" and "Gross capital additions to plant in service," for each unit and each of the years 2009–2018, to ensure that IPL would provide the capital expenditures (spending each year) and capital additions (investment transferred from CWIP to plant-in-service each year). IR 1-SC-3(h) and (i) Confidential (Chernick Dir. Confidential Ex. SC-5). IPL answered neither of these questions, instead saying only "See IPL FERC Form 1 pages 402-403 lines 13-17 for plant balances by plant unit." As I explained above, the FERC

A: In *In Re Interstate Power and Light Company*, RPU-2017-0002, IPL provided forecasts for capital additions for its shares of each plant.[11] Table 8 shows those estimates, restated to dollars per kilowatt for IPL's share of the units.[12] Since Ottumwa had major retrofits planned for 2017 and 2018, I computed its average additions without those years.

Table 8: IP&L Forecasts of Coal Total Capital Additions ($/kW)

	2017	2018	2019	2020	Average	2019-2020
Burlington	$15.1	$8.8	$9.0	$9.0	$10.5	
Neal	$27.3	$32.0	$21.8	$21.7	$25.7	
Lansing	$84.9	$58.4	$86.6	$99.5	$82.3	
Louisa	$82.4	$15.9	$13.4	$13.4	$31.3	
Ottumwa	$121.8	$85.6	$27.6	$48.4	$70.8	$37.96

Source: Chernick Dir. Ex. SC-6.

As shown in Table 9, the average capital additions that IP&L forecast in 2017 are higher than the historical averages I computed, except for Burlington, which is on a glide path to retirement. Most of these differences probably result from the fact that the historical data are net of retirements, and thus represent just a portion of the additions.

Table 9: Comparison of Total Forecast and Net Historical Capital Additions

	Forecast Total		Historical Net		Forecast Total ÷ Hist Net	
	Average	w/o outliers	Average	w/o outliers	Average	w/o outliers
Burlington	$10.5	$10.5	$23.6	$23.6	0.4	0.4
Neal	$25.7	$25.7	$30.8	$4.1	0.8	6.3
Lansing	$82.3	$82.3	$53.5	$14.7	1.5	5.6
Louisa	$31.3	$31.3	$0.7	$0.7	47.4	47.4
Ottumwa	$70.8	$38.0	$77.0	$13.5	0.9	2.8

Q: Did IPL publicly update its capital additions forecast in this proceeding?

A: No.

[11] IR 1-SC-7 Attachment A from RPU-2017-0002 (Chernick Dir. Ex. SC-6).

[12] I excluded Prairie Creek, which will be mostly gas-fired.

Q: Are you aware of any conditions that would tend to require large capital additions to continue operating any of the remaining IPL coal resources?

A: Yes. At least Lansing and Ottumwa face requirements for water-related environmental retrofits. I discuss those costs in the confidential Section IV.C.3.

D. Overheads

Q: What other costs are associated with continuing operation of the marginal coal units?

A: In addition to the O&M costs reported in the FERC Form 1 (e.g., page 402) for each plant, running the coal units incurs other costs that are recorded in other accounts, including:

- Labor-related overheads.
- Property insurance. (Detailed in 1-SC-03(g) CONF)
- Administrative costs, such as legal, human resources, supervision, regulatory and public affairs.
- Office expenses related to administration.
- Maintenance of the step-up transformers and other dedicated transmission equipment.

Q: How large are these indirect costs?

A: One way to address that question is to examine the extent to which the lead owner of each plant marks up its O&M costs to include these other costs. Four IPL coal units are jointly owned with MidAmerican, which is the lead owner Louisa, Neal 3 and Neal 4, and also own a portion of Ottumwa, as well as NorthWestern, which owns part of Neal 4. In general, the lead owner of a jointly owned plant carries most of the non-generation accounts on its own books and charges the point owners for their share of direct operating costs and of the indirect costs. From the 2014 to 2017 FERC Form 1 data for the various owners, the non-fuel O&M per kWh charged to the joint owner exceeds that reported by the lead owner by 40% to 58%, as shown in Table 10.

Table 10: Implied Overheads for Jointly-Owned Plants, Non-Fuel O&M

		$/MWh		Markup		
		IPL	**MidAm**	**IPL**	**MidAm**	**NorthWestern**
2018	**Neal 3**	$18.2	$12.4	1.473		
	Neal 4	$9.2	$6.2	1.484		1.629
	Louisa	$6.4	$4.2	1.507		
	Ottumwa	$4.5	$6.7		1.492	
2017	**Neal 3**	$12.8	$8.1	1.582		
	Neal 4	$10.7	$6.8	1.565		1.641
	Louisa	$12.3	$10.2	1.209		
	Ottumwa	$4.1	$6.3		1.520	
2016	**Neal 3**	$12.5	$7.9	1.584		
	Neal 4	$10.2	$6.4	1.587		1.581
	Louisa	$7.5	$4.9	1.539		
	Ottumwa	$4.5	$7.9		1.759	
2015	**Neal 3**	$12.4	$7.6	1.624		
	Neal 4	$6.6	$4.5	1.468		1.211
	Louisa	$6.7	$4.7	1.412		
	Ottumwa	$4.1	$6.8		1.661	
2014	**Neal 3**	$17.2	$14.2	1.214		
	Neal 4	$6.6	$4.7	1.383		1.431
	Louisa	$6.0	$4.1	1.441		
	Ottumwa	$6.4	$8.7		1.365	
2013	**Neal 3**	$8.0	$5.8	1.388		
	Neal 4	$12.2	$11.1	1.093		0.911
	Louisa	$8.8	$7.1	1.241		
	Ottumwa	$3.8	$6.0		1.585	
Average	**Neal 3**			1.477		
	Neal 4			1.226		1.401
	Louisa			1.392		
	Ottumwa				1.564	

The markups are very similar among the three utilities and the four units. The prices reported by IPL for Louisa, Neal 3, and Neal 4 already include the overheads added by MidAmerican. For the other units (Prairie Creek 1&3, Lansing, Burlington, and Ottumwa), the FERC data suggest adding about 50% in overheads to the non-fuel O&M costs.

In addition, as shown in Table 11, the joint owners also pay about 8% more than MidAmerican does for Neal fuel, suggesting that there are overheads excluded from MidAmerican's reported Neal fuel costs, as well. The Louisa and Ottumwa fuel costs reported for the two owners are very similar.

Table 11: Implied Overheads for Jointly-Owned Plants, Fuel

		$/MWh		Markup		
		IPL	MidAm	IPL	MidAm	NorthWestern
2018	Neal 3	$18.9	$17.4	1.086		
	Neal 4	$18.4	$16.7	1.100		
	Louisa	$17.6	$18.6	0.944		1.194
	Ottumwa	$21.1	$22.3		1.061	
2017	Neal 3	$19.9	$18.2	1.089		
	Neal 4	$20.9	$19.2	1.090		
	Louisa	$19.6	$19.6	1.001		1.134
	Ottumwa	$19.4	$19.2		0.990	
2016	Neal 3	$19.8	$18.0	1.100		
	Neal 4	$18.4	$17.3	1.066		
	Louisa	$18.7	$18.1	1.031		1.067
	Ottumwa	$19.6	$19.7		1.008	
2015	Neal 3	$20.4	$19.5	1.047		
	Neal 4	$18.9	$18.0	1.054		
	Louisa	$19.4	$19.3	1.007		1.072
	Ottumwa	$20.0	$20.0		1.003	
2014	Neal 3	$20.3	$19.6	1.036		
	Neal 4	$19.7	$18.5	1.067		
	Louisa	$18.3	$18.6	0.983		1.081
	Ottumwa	$20.9	$21.3		1.016	
2013	Neal 3	$19.1	$18.8	1.019		
	Neal 4	$18.7	$17.9	1.049		
	Louisa	$0.0	$0.0			1.008
	Ottumwa	$0.0	$0.0			
Average	Neal 3			1.086		
	Neal 4			1.100		
	Louisa			0.944		1.194
	Ottumwa				1.061	

From these comparisons, it appears that the indirect O&M costs not reflected in the unit-specific data are on the order of 50% of direct non-fuel O&M. IPL's fuel-related overheads appear to be on the order of 1.5%.

Q: Are there any other categories of expense that would not appear in the plant-specific data in the FERC Form 1?

A: Yes. IPL "pays a replacement tax in lieu of property taxes… The equivalent cost of property taxes that a generation plant produces towards the overall replacement tax burden is $0.0006 per net kWh generated…."[13] This payment adds 0.06¢/kWh or $0.6/MWh to the cost of running the coal units. Depending on the location and ownership of replacement power sources, IPL could pay this fee on that replacement power, so I do not include this separate cost item.

E. Cost Summary

Q: How do the cost components (fuel, O&M, overheads and capital expenditures) add up to a cost per megawatt-hour for continued operation?

A: I computed the total costs of continuing to operate each coal unit in Table 12 from the fuel and O&M in Table 4, capital additions in Table 8, and the overheads in Table 10 and Table 11. I do not list overheads for the MidAmerican-operated units, since I assume those costs are in the reported plant O&M. In the years with net capital additions that were negative, or appeared to be associated with major emissions projects, I used the average

[13] 1-SC-03(f) Confidential (Chernick Dir. Confidential Ex. SC-5).

net additions without those outliers. As demonstrated in Table 9, these estimates probably understate actual capital additions.

Table 12: Costs of Running IPL Coal Units ($/MWh)

		OH %	2013	2014	2015	2016	2017	2018
Burlington	Fuel	1.5%	$18.7	$19.7	$19.0	$18.4	$20.9	$17.6
	O&M	50%	$12.2	$6.6	$6.6	$10.2	$10.7	$5.0
	Cap Adds		$4.7	$11.9	$1.6	$5.3	$2.7	$0.6
	Overheads		$6.4	$3.6	$3.6	$5.4	$5.7	$2.8
	Total Cost		$41.9	$41.7	$30.7	$39.3	$40.0	$26.0
Neal 3	Fuel		$19.1	$20.3	$20.4	$19.9	$19.9	$18.9
	O&M		$8.0	$17.2	$12.4	$12.5	$12.8	$18.2
	Cap Adds		*$5.5*	*$5.5*	$8.2	$3.5	$0.7	$9.5
	Total Cost		$32.6	$43.0	$41.0	$35.9	$33.3	$46.7
Neal 4	Fuel		$30.6	$31.0	$32.1	$32.2	$31.0	$18.4
	O&M		$6.9	$6.8	$9.7	$9.3	$8.5	$9.2
	Cap Adds		*$1.8*	$2.6	$0.9	$1.3	$2.2	*$1.8*
	Total Cost		$39.2	$40.4	$42.7	$42.8	$41.7	$29.4
Lansing 4	Fuel	1.5%	$18.2	$14.9	$16.4	$16.6	$17.6	$28.4
	O&M	50%	$4.6	$4.9	$5.6	$5.9	$6.1	$8.9
	Cap Adds		$1.2	$1.5	*$2.9*	$1.1	$10.8	$0.0
	Overheads		$2.6	$2.7	$3.1	$3.2	$3.3	$4.9
	Total Cost		$26.4	$23.8	$28.0	$26.7	$37.8	$42.1
Louisa	Fuel		$17.1	$18.3	$19.4	$18.7	$19.6	$17.6
	O&M		$8.9	$6.0	$6.7	$7.5	$12.3	$6.4
	Cap Adds		$0.8	$0.7	$1.3	$0.4	$6.9	$7.0
	Total Cost		$26.8	$25.0	$27.4	$26.6	$38.9	$30.9
Ottumwa	Fuel	1.5%	$22.0	$20.9	$20.0	$19.6	$19.4	$21.1
	O&M	50%	$3.8	$6.4	$4.1	$4.5	$4.1	$4.5
	Cap Adds		$4.4	*$4.5*	*$4.5*	$4.1	$6.6	$3.0
	Overheads		$2.2	$3.5	$2.3	$2.5	$2.4	$2.6
	Total Cost		$32.4	$35.4	$30.9	$30.7	$32.5	$31.1

The all-in cost of keeping these plants operating has been around $30/MWh for Louisa, the low $30s range for Ottumwa and Lansing, about

$35/MWh for Burlington, and about $40/MWh for the Neal units. Prairie Creek 4 cost about $100/MWh as a coal plant. Better data on total capital additions would increase the costs for most of these units.

F. Market Energy Prices

1. Historical Prices

Q: What MISO market energy prices have the IPL coal units faced?

A: Table 13 summarizes the average locational marginal price (LMP) for each of IPL's coal resources, for 2014–2018. These are the prices that MISO would have paid IPL for energy delivered evenly throughout the year.

Table 13: Annual Average LMPs by Year, $/MWh

	Burlington	Neal 3&4	Lansing	Louisa	Ottumwa
2014	$34.8	$23.7	$31.3	$29.2	$24.1
2015	$22.3	$18.2	$24.5	$20.3	$19.5
2016	$23.4	$19.9	$24.2	$21.4	$20.6
2017	$25.2	$22.2	$24.8	$24.6	$23.0
2018	$32.2	$25.6	$25.2	$27.3	$22.9

For most of the IPL coal units, energy prices were highest in 2014 and the 2018 prices have recovered slightly from the low prices in 2015–2017.

Table 14 provides additional data on the variability of the hourly MISO LMPs experienced by the IPL coal units in 2018. The hourly mean price across units ranged from $32.17 per MWh for Burlington to $22.85 per MWh for Ottumwa. The 50th percentile price across units ranged from $24.90/MWh to $20.93/MWh.

Table 14: 2018 Hourly Energy Prices ($/MWh) by Unit

	Burlington	Neal 3	Neal 4	Lansing	Louisa	Ottumwa
Mean	32.17	25.57	25.55	25.22	27.33	22.85
Minimum	-125.74	-10.97	-11.00	-184.61	-55.39	-333.01
25th Percentile	21.30	18.48	18.46	19.96	20.54	18.27
50th Percentile	24.90	21.80	21.78	22.87	23.40	20.93
75th Percentile	32.96	27.94	27.93	27.69	29.52	26.42
Maximum	925.23	492.75	492.53	495.42	508.39	475.19

Q: How do these energy prices compare to the short-run costs of producing energy prices from these units?

A: Table 15 compares the energy prices that could theoretically be earned by each unit to the short-run costs of producing energy at each unit. The excess of the energy price over the cost of producing that energy is the energy margin. This metric is distinct from the long-run economics of the units, which include the operating and capital costs that are required to prepare the plant to run. To calculate the short-run energy margin for each unit, I started by estimating the short-run cost for each unit as the sum of fuel costs and the 2012–2017 estimate of variable O&M (VOM) from the 2018 Bloomberg New Energy Finance (BNEF) U.S. coal fleet analysis. The VOM values ranged from $3.9/MWh to $4.7/MWh for the various units.

I then counted the number of hours in which the market energy price exceeded the short-run cost. These values varied from just 15% of the hours for Neal Unit 4 to 74% of the hours for the cogenerating Prairie Creek Units 1 and 3. I also computed the average LMP in the hours when it exceeded the short-run cost. The LMP in those profitable hours varies inversely with the number of profitable hours.[14]

Table 15: Energy Margin by Unit with Perfect Dispatch (2018 $/MWh)

	Burlington	Neal 3	Neal 4	Lansing 4	Louisa	Ottumwa	Prairie Creek 1,3
Fuel + VOM	$23.5	$23.9	$33.1	$23.1	$22.3	$25.2	$20.2
When LMP exceeds Fuel + VOM							
Number of Hours	5,042	3,381	1,313	4,233	5,072	2,552	6,488
% of hours	57.6%	38.6%	15.0%	48.3%	57.9%	29.1%	74.1%
Average LMP	$41.4	$37.1	$52.1	$34.1	$33.2	$38.1	$30.9
Energy Margin = LMP – (Fuel + VOM)							
$/MWh	$17.9	$13.3	$18.9	$11.0	$10.8	$12.9	$10.7
$/kW-year	$90.3	$45.0	$24.8	$46.6	$54.8	$32.9	$69.4

In the last section of Table 15, I computed the average energy margin for each unit in the profitable hours, in dollars per megawatt-hour (the difference between average LMP and the variable running cost) and in $/kW-year (the $/MWh margin times the number of profitable hours). That is the maximum energy margin that the plant could earn, if it somehow could be dispatched just in the profitable hours.

Q: How does the percentage of profitable hours compare to the units' capacity factors?

A: As shown in Table 16, most of the units ran much more than was profitable. Ottumwa ran twice as much as would have been profitable, while Neal 4 ran almost 4 times as much. On the other hand, Lansing generated less energy

[14] In this section, I consider whether the units are profitable to run in a particular hour, once IPL has committed to the capital additions and fixed O&M necessary to make the plant available. Elsewhere, in Section III.G, below, I consider the annual profitability of the units, including the capital additions and fixed O&M. I do not reflect the sunk capital costs of the units in any of my analyses.

than it would have if it had been able to operate at full power in every profitable hour, and not in any unprofitable hour.

Table 16: Comparison of Profitable Hours to Capacity Factors, 2018

	Profitable Hours (%)	Capacity Factor (%)	Difference in % Points	Ratio
Burlington	57.6%	64.5%	7.0%	1.12
Neal 3	38.6%	51.0%	12.4%	1.32
Neal 4	15.0%	54.8%	39.8%	3.65
Lansing 4	48.3%	40.6%	-7.7%	0.84
Louisa	57.9%	74.9%	17.0%	1.29
Ottumwa	29.1%	59.4%	30.3%	2.04

If the coal units were always available and able to ramp up immediately to full power in the profitable hours and shut down immediately when LMP fell, the capacity factor should be very close to the profitable hours. In reality, each unit is unavailable in some high-value hours due to forced and maintenance outages. Since large steam plants start up and shut down slowly and have other constraints on turning on and off, or even ramping up and down, they inevitably fail to operate in some high-priced hours and are forced to operate in some low-priced hours in order to reduce wear and tear on the plant and to be available when prices are higher in adjacent periods.

Table 16 shows that most of the units had capacity factors higher than the percentage of hours in which operation would be profitable. Except for Lansing, all of the units appear to be dispatched more than would be profitable. Running when market energy prices are low, or failing to run when prices are high reduces the energy margin, leaving even less cash flow to offset the long-run fixed and capital costs required to keep the unit available.

Q: What are the constraints on IPL's cycling of its coal plants?

A: Very little public information is available on these technical parameters, but according to EIA's Form 860, the Prairie Creek units require either "12 hours" from cold shutdown to full load, while IPL's other coal units require "over 12 hours." Its combustion turbine units require one hour to reach full load.[15]

Q: What were the market prices when the units were actually dispatched?

A: Table 17 shows the energy margin for each unit when it actually ran in 2018.[16] The average LMPs in the hours in which the units ran were lower than the LMPs under perfect dispatch (Table 15). For three of the units (Burlington, Lansing and Ottumwa), the average LMPs in the hours of operation were lower than the simple average over the year, as shown in Table 14.

Energy margin was lower for each of the units than with the ideal dispatch of Table 15, the hours of operation were higher and the average LMP was lower. In fact, two units, Neal 4 and Ottumwa, appear to have lost money just on running costs, even before accounting for fixed O&M, capital additions and overheads.

[15] Most combined-cycle plants can reach a substantial share of the capacity of the combustion turbines in less than an hour, although the heat-recovery steam generator may take longer to reach full capacity.

[16] The EPA database does not have the Prairie Creek output, so those units are not included.

1 **Table 17: 2018 Energy Margin by Unit, as Dispatched**

	Burlington	Neal 3	Neal 4	Lansing 4	Louisa	Ottumwa
Fuel + VOM	$23.5	$23.9	$33.1	$23.1	$22.3	$25.2
When the Unit was Operating						
Number of Hours	7,173	5,725	6,548	5,801	7,857	7,027
% of hours	81.9%	65.4%	74.7%	66.2%	89.7%	80.2%
Average LMP	$29.0	$26.4	$26.7	$24.1	$27.5	$22.6
Energy Margin = LMP – (Fuel + VOM)						
$/MWh	$5.5	$2.5	-$6.5	$0.9	$5.1	-$2.5
$/kW-year	$39.2	$14.6	-$42.5	$5.5	$40.3	-$17.9

2 Table 18 summarizes my estimate of the energy margin for each coal
3 unit for each year, 2014–2018. Lansing's margin has been consistently
4 positive but has declined consistently and dramatically over the years, as
5 Lansing's costs have grown and the market prices have fallen. Louisa's
6 margin was positive four out of the five years, Neal 3's margin was positive
7 three times, and Burlington's twice. In the last five years, Neal 4 and
8 Ottumwa never earned as much in the energy market as they cost in fuel and
9 VOM. Their energy deficits have been consistently larger than possible
10 capacity revenues, as discussed in the next section.

11 **Table 18: Annual Energy Margin by Unit, as Dispatched**

	Burlington	Neal 3	Neal 4	Lansing	Louisa	Ottumwa
$/MWh						
2014	$9.1	$1.9	-$9.2	$6.6	$6.7	-$6.5
2015	-$2.2	-$2.9	-$14.9	$2.4	-$1.3	-$6.5
2016	-$0.9	-$0.3	-$11.9	$2.4	$0.5	-$5.4
2017	-$0.1	$1.0	-$8.7	$1.2	$2.6	-$3.6
2018	$5.5	$2.5	-$6.5	$0.9	$5.1	-$2.5
$/kW-year						
2014	$64.3	$10.7	-$76.4	$48.6	$56.1	-$37.1
2015	-$15.2	-$12.9	-$127.5	$13.2	-$9.3	-$51.2
2016	-$6.5	-$1.4	-$67.7	$13.7	$3.3	-$40.9
2017	-$0.5	$5.0	-$41.8	$7.3	$15.5	-$27.0
2018	$39.2	$14.6	-$42.5	$5.5	$40.3	-$17.9

Barring some abrupt change in the energy market, Ottumwa and Neal 4 are clearly uneconomic, even before considering the non-dispatch costs of having the units available.

2. *Future Energy Prices*

Q: Are market prices for electric energy in Iowa likely to increase dramatically over the next several years?

A: No. While prices may spike occasionally, indications are that electric market prices will rise only slowly. Table 19 shows the simple average of the ICE forward prices for MISO's Illinois and Minnesota hub from July 19, 2019, for as far out as those products are traded. The prices mostly fall from the second half of 2019, through 2023.[17]

Table 19: MISO Forward Prices ($/MWh)

MISO Hub	Illinois		Minnesota	
Period	On	Off	On	Off
ICE code	MLB	MLD	MDP	MDO
2H19	$30.31	$21.87	$25.76	$18.91
2020	$30.00	$22.02	$26.88	$18.75
2021	$28.88	$21.49	$25.98	$18.09
2022	$28.50	$21.38	$25.45	$18.08
2023	$27.60	$21.75	$24.76	$18.66

Q: Is there any public information on likely future electric energy prices?

A: Not directly. However, one major driver of electric energy prices is the cost of natural gas. Table 20 shows Henry Hub gas prices for the NYMEX forwards (the HH contract) and from the EIA's 2019 Annual Energy Outlook reference case. The 2019 price in the NYMEX column is the average of

[17] https://www.theice.com/marketdata/reports/142.

monthly actual spot price to mid-July and forwards thereafter. The EIA's projection looks to be somewhat bullish in the short term. Interestingly, the forwards for MISO energy prices fall from 2019 through 2023, even though gas-price futures and forecasts are rising.

Table 20: Henry Hub Gas Price Projections ($/MMBtu)

	NYMEX	EIA
2017		$3.02
2018		$2.99
2019	$2.54	$3.10
2020	$2.49	$3.25
2021	$2.55	$3.24
2022	$2.60	$3.33
2023	$2.67	$3.56
2024	$2.76	$3.84
2025	$2.90	$4.20
2026	$3.02	$4.39
2027	$3.17	$4.52
2028	$3.29	$4.72
2029	$3.41	$4.84
2030	$3.54	$5.00
2031	$3.65	$5.09

G. Capacity Prices and Revenues

Q: Is capacity very valuable in the MISO market?

A: No. Table 21 shows the clearing prices in Zone 3 (which includes all of Iowa) for each of the Planning Reserve Auctions (PRAs) that MISO has conducted.[18]

[18] From "2018/2019 Planning Resource Auction Results," MISO, April 13, 2018, p. 8.

Table 21: MISO Zone 3 Capacity Prices

Planning Year	Per unit of UCAP		$/MWh at capacity factor of		
	$/MW-day	$/kW-year	40%	50%	60%
2014/15	$16.75	$6.11	$1.74	$1.40	$1.16
2015/16	$3.48	$1.27	$0.36	$0.29	$0.24
2016/17	$72.00	$26.28	$7.50	$6.00	$5.00
2017/18	$1.50	$0.55	$0.16	$0.13	$0.10
2018/19	$10.00	$3.65	$1.04	$1.04	$1.04
2019/20	$2.99	$1.09	$0.31	$0.25	$0.21
Average	$17.79	$6.49	$1.85	$1.48	$1.23

Zone 3 has always cleared at the same price as Zones 2, 5, 6, and 7, and usually with other zones, as well. In three of the five PRAs (those with Zone 3 prices over $4/MW-day), Zone 1, western Wisconsin and Minnesota, cleared at much lower prices than Zone 3. If transmission capacity out of Zone 1 increases (to allow wind exports, or better integrate the MISO system), the capacity surplus in Zone 1 is likely to reduce prices in Zone 3.

There is no clear trend in the capacity prices over the five capacity auctions, despite the large amount of coal capacity retired in this period.

Q: What are the capacity prices in other regions?

A: Capacity markets are operated by only four ISOs: MISO, PJM, NYISO and ISO-NE. The SPP has an administrative penalty for capacity deficiencies, ERCOT has only an energy market, and the CA ISO requires that each participant contribute to resource adequacy and collects data on bilateral transactions to meet that standard.[19]

The capacity prices in the Midwestern portion of PJM, the ISO area most similar to MISO, have averaged about $36/kW-year since its first capacity auction for 2007/08, through the 2021/22 capacity period. Those

[19] The average price reported in for 2017 contract, for 2017 through 2021, averaged $21/kW-year for the unconstrained portions of the system.

prices are for capacity contracts with high penalties for non-performance.[20] Prices comparable to the MISO capacity product would be several percentage lower.

The prices for Upstate New York are more difficult to summarize, because NYISO conducts three types of capacity auctions (a seasonal strip auction every six months, a monthly auction every month for each of the remaining months of the season, and a spot price for each month). The average strip price for the latest sixty months for which the prices have been set (through October 2019) is under $23/kW-year, while the average spot price for the latest sixty months for which the prices have been set (through July 2019) is under $26/kW-year.

Capacity prices are higher in places where building capacity is difficult, land is scarce, labor is expensive, and transmission is constrained (e.g., New York City, New Jersey), but those conditions are not typical of Iowa and neighboring parts of MISO.[21]

Both the PJM and NYISO capacity markets are dominated by non-utility generators who face greater risks building for a competitive market

[20] In the earlier years in which the PJM capacity market accepted both standard and high-performance capacity bids, I used the price for standard capacity, which is most comparable to the MISO capacity product.

[21] In New England, which largely meets the high-cost criteria, the ISO-NE has run forward capacity auctions since the 2010/11 delivery year, but most of those auctions have settled at administrative floors or ceilings. In the last five auctions, following the largely unanticipated retirement of capacity equivalent to over 10% of peak load, the capacity price has fallen from over $100/kW-year to $46/kW-year.

than do IPL and the other vertically-integrated utilities that dominate the MISO market.

H. Economics of IPL's Coal Plant Operations from Public Data

Q: How do the market revenues for the units compare to the forward-looking plant costs that you estimated in Table 12?

A: Table 22 shows the total costs, energy revenues and the capacity prices converted to millions of dollars for 2018.[22]

Table 22: Summary of IPL Average Coal Plant Costs and 2018 Revenues

		Burlington	Neal 3	Neal 4	Lansing	Louisa	Ottumwa
a	Cost 2015-2018 ($/MWh)	$34.0	$39.2	$39.1	$33.7	$30.9	$31.3
b	Energy Revenue 2018 ($/MWh)	$29.0	$26.4	$26.7	$24.1	$27.5	$22.6
c	2018 GWh	1,189	643	806	883	197	1,908
d	Margin with Energy ($M)	($5.9)	($8.2)	($10.0)	($8.5)	($0.7)	($16.6)
e	IPL Capacity Share	210.5	142.8	165.5	248.3	29.8	344.7
f	2018 Capacity Revenue ($M)	$0.8	$0.5	$0.6	$0.9	$0.1	$1.3
g	**Net profit ($M)**	**($5.2)**	**($7.7)**	**($9.4)**	**($7.6)**	**($0.6)**	**($15.3)**
	Profit per MWh	–$1.6	($4.4)	($12.0)	($11.7)	($8.6)	($2.8)
i	Profit per kW-year	($24.6)	($54.0)	($56.7)	($30.5)	($18.8)	($44.5)

Notes:
a From Table 12
b From Table 17
c From FERC Form 1
d = (b - a) × c ÷ 1,000
e From Table 1
f = e × $3.65 ÷ 1,000
g = d + f

[22] This analysis differs from the comparisons in Section III.F (e.g., Table 18), which included only short-run variable costs of the coal plants. This section looks at the total forward-going economics of the coal plants. The capacity revenues should be reduced about 5% to reflect the difference between rated and accredited capacity; that difference is inconsequential in this comparison.

As shown in Table 22, all of IPL's coal plants have been costing customers more money than they earned in the markets in 2018. Neal 3 cost customers $8.6 million, Neal 4 cost customers $10.8 million, Lansing cost customers $7.2 million, and Ottumwa cost customers $15.8 million.

If losses continue at this rate, IPL customers would be worse off by over $800 million through remaining life of the units. (Using book lives from IPL's 2018 FERC Form 1, p. 337, Account 312). IPL's planning documents suggest that the remaining lives are [redacted], but the potential losses would [redacted].[23]

Q: Is there any reason to expect that these units would have positive benefits for customers in the future?

A: I see no reason to expect that outcome. Most observers expect costs of renewables and storage to continue falling, and penetration of renewable energy resources in the Midwest MISO market continues to rise,[24] pushing down market energy prices and reducing the value of the coal plant output. The environmental retrofits required to comply with the Clean Water Act, discussed further below, and any future limits on carbon emissions will tend to make coal plants less economic.

Q: If IPL needed to purchase additional capacity to meet its MISO obligations, would that be expensive?

[23] Chernick Dir. Confidential Exhibit SC-3 Attachments A and B.

[24] About 1,000 MW of renewables were added in MISO so far in 2019, and another 6,000 MW are in various stages of planning and construction, for operation through 2021.

A: Not at the historical average market capacity prices. As shown in Table 21, the cost of capacity to replace generation with the range of capacity factors that the IPL coal units are likely to achieve is only about one or two dollars per MWh. If the coal energy is replaced by lower-cost wind or solar, which have some capacity value, that would contribute to satisfying IPL's capacity requirements.

IV. Additional Analyses from Confidential Data

A. Additional Historical Data

Q: What additional historical data did IPL provide confidentially?

A: In 1-SC-3 Confidential (Chernick Dir. Confidential Ex. SC-5), IPL provided annual energy revenues by unit for 2011–2018, as well as some data on outage rates and byproduct sales revenues. IPL failed to provide the total capital additions by unit.

Q: What energy revenues did IPL report?

A: Confidential Table 23 shows the energy revenues that IPL reported, by year, for the units of greatest interest in my analysis.

CONFIDENTIAL Table 23: IPL-Reported Energy Revenue by Unit[25]

	2012	2013	2014	2015	2016	2017	2018
Burlington	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lansing 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[25] Source: 1-SC-3 Confidential (Chernick Dir. Confidential Ex. SC-5.)

Q: How do these values compare to the energy revenues you estimated from the MISO hours LMPs and the EPA hourly gross generation pattern?

A: Confidential Table 24 provides that comparison for 2018. The estimated revenues are the $/MWh values from Table 15, times the IPL share of the unit's output for 2018.

Confidential Table 24: Comparison of Public Estimate of 2018 Energy Revenues to IPL Confidential Information, $M

	Burlington	Neal 3	Neal 4	Lansing	Louisa	Ottumwa
Estimated	$34.5	$16.5	$20.6	$22.3	$5.4	$43.7
IPL Reported	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Difference	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

IPL's reported energy revenues are [redacted] than my estimates from the EPA data. With these revenues, [redacted] would have uneconomic in 2018, although [redacted].

Q: What outage-rate data did IPL provide?

A: Confidential Table 25 provides IPL's data on forced outage rates.[26] It is not clear whether these data reflect all the outages and capacity deratings that MISO includes in the "Forced Outage and Deration Rate" to determine UCAP.

[26] 1-SC-3 Confidential (Chernick Dir. Confidential Ex. SC-5).

Confidential Table 25: IPL Coal Unit Forced Outage Rates

Plant	Unit	2013	2014	2015	2016	2017	2018	Average (2013–2018)
Burlington	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal North	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal South	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lansing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prairie Creek	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prairie Creek	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]

Q: What historical cost data did IPL provide confidentially?

A: IPL provided insurance costs, which I include in the overhead cost component.

Q: What byproduct revenues did IPL provide?

A: Confidential Table 26 shows the byproduct revenues from IPL-operated coal plants. IPL did not provide comparable data from Neal or Louisa. These values are quite small, compared to the costs of running the plants.

Confidential Table 26: Byproduct Revenues ($M)

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q: Have you updated your Table 22, using the revenues from Confidential Table 23 and the byproduct revenues in Confidential Table 26?

A: Yes. Confidential Table 27 provides that update.

Confidential Table 27: Summary of IPL Historical Coal Plant Costs and Revenues, Partially Confidential

		Burlington	Neal 3	Neal 4	Lansing	Louisa	Ottumwa
a	Cost 2015–2018 ($/MWh)	$34.0	$39.2	$39.1	$33.7	$30.9	$31.3
b	Energy Revenue 2018 ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
c	2018 GWh	1,189	643	806	883	197	1,908
d	Margin with Energy ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
e	IPL Capacity Share	210.5	142.8	165.5	248.3	29.8	344.7
f	2018 Capacity Revenue ($M)	$0.8	$0.5	$0.6	$0.9	$0.1	$1.3
g	2018 Byproduct Revenue ($M)	[redacted]			[redacted]		[redacted]
h	Net profit ($M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
a From Table 12
b From 1-SC-03a CONF ÷ c × 1,000
c From FERC Form 1
d = (b - a) × c ÷ 1,000
e From Table 1
f = e × $3.65 ÷ 1,000
g From 1-SC-03c CONF ÷ 1,000
h = d + f + g

Using the historical data that IPL provided does not change my conclusion that the coal plants' revenues have not been covering their costs.

Q: How much extra would IPL customers pay annually in order to keep the coal plants operating, at the profit levels in Confidential Table 27?

A: IPL customers can expect to pay $[redacted] more annually to keep the plants operating at the 2018 unit output levels than if [redacted] were replaced at market prices.

B. IPL Analyses of the Economics of its Coal Resources

Q: What analyses of coal-plant cost and performance did IPL provide in discovery?

A: The Company provided confidential materials pertaining to the operation and usefulness of their existing fleet in attachments to IRs 1-SC-22 Confidential and 1-SC-24 Supplemental Confidential.[27] In 1-SC-22 Confidential, IPL

[27] Chernick Dir. Confidential Exhibits SC-4 and SC-3, respectively.

provided two confidential attachments: "OGS SCR presentation December 2016" (Confidential Ex. SC-4 Att. A) and "Kitchen Rebuttal Testimony" (Confidential Ex. SC-4 Att. B) on "the economics of the continued operation on the Ottumwa Generating Station in docket EPB-2016-0150." 1-SC-24 Supp Confidential provides two confidential attachments containing "IPL's current generation planning assumptions and analysis regarding its generation fleet." The first attachment outlines IPL's "current generation planning assumptions and analysis…." The second document is [redacted]

Q: What can you determine regarding the analyses for Ottumwa described in the attachments to 1-SC-22 Confidential?

A: The two attachments that IPL provided in 1-SC-22 Confidential (Chernick Dir. Confidential Exs. SC-4, Attachments A & B) regarding the continued economics of operating the Ottumwa generating station are quite summary and high-level, so many of the details of the analysis are not revealed. IPL [redacted][28] Specifically:

[28] To be clear, I am not addressing IPL's past decisions to install the SCR (or other pollution controls) to comply with mandates of the Consent Decree with the EPA and other parties. Nor am I questioning whether IPL should recover the resulting costs. I discuss this analysis solely to examine whether Ottumwa is likely to be economic in the future.

- [redacted] The ICE futures for the MISO Illinois Hub in 2023 are $27.6/MWh for peak and $21.8/MWh for off-peak,[29] as shown in Table 19, compared to IPL's assumptions of [redacted]MWh for peak and [redacted]MWh for off-peak in Confidential Attachment A. [redacted]
- IPL assumes capacity prices for 2025 of about [redacted]/kW-year.[30] The graph on p. 39 of Confidential Attachment A shows IPL assumed capacity prices of about [redacted]. As shown in my Table 21, above, actual capacity prices have been in the single digits (under $10/kW-year, and sometime under $1) since 2017.
- IPL's study used gas prices that are [redacted]. The following table (from Confidential Attachment A, p. 17), shows the prices assumed by IPL in various iterations of the study. At IPL's projected 2020 price and the low end of the price range for 2025, [redacted], and is [redacted] its historical fixed O&M and capital additions, which have averaged about $8.5 million annually for O&M and about $8.7 million for capital additions, from the FERC Form data excluding outliers, or about $[redacted] in annual capital

[29] https://www.theice.com/marketdata/reports/142.

[30] $[redacted] for Ottumwa (Attachment A, p. 18), divided by [redacted] MW accredited capacity (Attachment A, p. 28).

additions from IPL's forecast (see Confidential Table 35) . The Henry Hub futures are currently $2.60/MMBtu for 2020 and $2.90/MMBtu for 2025, so a new analysis would [redacted].

Confidential Table 28: Ottumwa Performance and Energy Margin under Varying IPL Gas Price Assumptions

[redacted]

[redacted].

Q: What can you determine regarding "IPL's current generation planning assumptions and analysis regarding its generation fleet"?

A: 1-SC-24 Supplemental Confidential Attachment A (Chernick Dir. Confidential Ex. SC-3 Att. A), dated [redacted]

However, it does contain the following key pieces of information:

- Table 1A indicates that IPL assumes that the market [redacted].
- [redacted]

- [redacted], every reference to [redacted] in its "current generation planning assumptions and analysis" [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
    - [redacted]
    - [redacted]
- [redacted]
- [redacted]
- [redacted].

[redacted]

Q: What information is in the [redacted]?

A: 1-SC-24 Supplemental Confidential Attachment B (Chernick Dir. Confidential Ex. SC-3(b)) is a [redacted]

- [redacted]
- [redacted].

Confidential Table 29: Comparison of Actual and IPL-forecast Capacity Prices ($/kW-year)

	IPL	Actual
2018	[redacted]	$3.7
2019	[redacted]	$1.1
2020	[redacted]	

[31] IPL points out that "Confidential Attachments A and B…are subject to change, and do not represent a final decision by IPL as to the continued operation or retirement of any specific generation units." (Chernick Dir. Confidential Ex. SC-3)

2021	[redacted]
2022	
2023	
2024	

- [redacted]

Confidential Table 30: IPL Projected [redacted] Capital Additions ($M)

[redacted]

- [redacted]

Confidential Table 31: IPL Projected [redacted] O&M Cost ($M)

	O&M ($M)	
Year	**Operate**	**Retire**
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	
2023	[redacted]	
2024	[redacted]	
2025	[redacted]	
2026	[redacted]	
2027	[redacted]	
2028	[redacted]	
2029	[redacted]	
2030	[redacted]	
2031	[redacted]	
2032	[redacted]	
2033	[redacted]	
2034	[redacted]	
2035	[redacted]	
2036	[redacted]	
2037	[redacted]	

Overall, this study indicates that [redacted] are at least as financially challenged as [redacted], they must also be [redacted].

C. Confidential Performance and Cost Data

1. Performance data

Q: What additional performance measures have you compiled for the IPL coal units?

A: Confidential Table 32 compares the MISO-reported average outage rate for various size coal units to IPL's confidential projections of the forced outage rates for its coal units for 2019–2021. While there are differences by unit, the IPL projections [redacted] the MISO data.

Confidential Table 32: Coal Plant Forced Outage and Deration Rate

Plant	Unit	[redacted]	MISO Group Average[e]
Burlington	1	[redacted]	9.8%
Neal North	3	[redacted]	9.3%
Neal South	4	[redacted]	8.2%
Lansing	4	[redacted]	9.8%
Louisa	1	[redacted]	8.2%
Ottumwa	1	[redacted]	8.2%

[a] IR 1-SC-13 Confidential, Chernick Dir. Confidential Ex. SC-7.
[b] "Planning Year 2019–2020 Loss of Load Expectation Study Report," Loss of Load Expectation Working Group, October 17, 2018, Table 4-1.

Q: How do these outage rates affect the accredited capacity of IPL's coal units?

A: IR 1-SC-22, Confidential Attachment A (Chernick Dir. Confidential Ex. SC-4(a)), p. 28, shows accredited capacity of [redacted] MW for Lansing, [redacted] MW for IPL's share of Ottumwa (falling to [redacted] in 2019, probably due to the SCR load), and a total of [redacted] MW for IPL's share of [redacted]. These values are about [redacted]% of IPL's share of coal plants' capacity, which I have used elsewhere in this testimony for computing capacity revenues. My analyses thus somewhat overstate the capacity revenue of the coal plants.

2. *Coal Plant O&M*

Q: Did IPL provide any confidential forecast of O&M expenditures for the coal plants?

A: Yes. IR IBEC-19, Confidential Attachment A, from RPU 2016-0005 (Chernick Dir. Confidential Ex. SC-8), provides estimates of the 2020 and

2025 fuel and variable operating and maintenance costs for five of IPL's coal units, as shown in Confidential Table 33.

Confidential Table 33: IPL projections of Fuel and Variable O&M

	Fuel Cost ($/MWh)		Production Cost ($/MWh)		Variable O&M ($/MWh)	
	2020	2025	2020	2025	2020	2025
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lansing 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

These variable O&M values straddle the estimates that I used in Section III.F. The total fuel and variable O&M values in Confidential Table 33 are [redacted] than those I used in Table 15. My analysis is thus [redacted] in concluding that the units are uneconomic.

In the economic analysis of Ottumwa discussed in Section IV.B, IPL [redacted][32] [redacted] from the approximately $8.5 million reported in recent FERC Form 1 reports.

For [redacted], I described IPL's assumptions above.

3. *Coal Plant Capital Additions*

Q: Did IPL provide its any confidential forecast of capital additions for the coal plants?

---

[32] IR 1-SC-22, Confidential Attachment A, p. 18 (Chernick Dir. Confidential Ex. SC-4(a)). Some portion of the [redacted] listed in IR 1-SC-24 Supp Confidential may also represent O&M.

A: The only long-term forecasts were in the economic analyses of [redacted] discussed in Section IV.B. We know that IPL expected typical annual capital additions of $[redacted] in 2025.[33] For [redacted], IPL projected $[redacted] in 2020, escalating roughly with inflation, with [redacted] in additional environmental compliance costs through [redacted]. Chernick Dir. Confidential Ex. SC-3 Att. B.

IPL also provided short-term forecasts for 2019 and 2020 construction expenditures, by project or budget item, in Fields' Direct Testimony, Exhibit 11 Confidential Workpaper J-6. These values reflect IPL's spending in each year, not the net increase of plant in service shown in Table 5.

Confidential Table 34 provides the sum of those projections for each coal plant. The data for Prairie Creek would cover both the coal-fired units 1 and 3, and the gas-fired unit 4. IPL reports only a single line item for all three of the MidAmerican-operated units.

Confidential Table 34: IPL Short-Term Construction-Expenditures Forecasts

	$ Millions		$/kW-year	
Resource	**2019**	**2020**	**2019**	**2020**
Burlington	[redacted]	[redacted]	[redacted]	[redacted]
Lansing	[redacted]	[redacted]	[redacted]	[redacted]
Neal & Louisa	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]

The lack of capital additions for [redacted] is consistent with the decision to retire that plant. In contrast, IPL is increasing its investment in [redacted], which will increase ratepayers' losses for plants that should be retired. The planned expenditures for 2019 and 2020 are much

[33] 1-SC-22, Confidential Attachment A, p. 18 (Chernick Dir. Confidential Ex. SC-4 Att. A).

higher than the net additions in Table 5. The Neal and Louisa additions are [redacted].

IR 1-SC-15 Confidential (Chernick Dir. Confidential Ex. SC-9), provides IPL's most recent forecast of capital expenditures for each of its coal plants, summarized in Confidential Table 35. These projections are somewhat different (and higher) than those summarized in Confidential Table 34.[34]

Confidential Table 35: IPL Medium-Term Construction-Expenditure Forecasts

($M)

	2019	2020	2021	2022	2023
Burlington	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Lansing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Louisa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Overall, these projections indicate that continuing to operate the plants will require future capital additions [redacted], the historical investments. Additional capital additions to plants that are currently uneconomic will increase ratepayers' losses associated with continued operation.

Q: What additional environmental compliance obligations does IPL face at its coal plants that could require significant additional capital expenditures?

A: IPL faces [redacted] capital investment decisions at Lansing and Ottumwa in the near future to comply with water-protection and waste-management laws, indicating that a retirement decision must be made immediately around those

[34] I do not know why this responses differ. I also do not know why IPL projects additions at [redacted].

plants to avoid an unnecessary and imprudent commitment of ratepayer dollars to uneconomic plants. I do not have comparable data for the units operated by MidAmerican.

IPL's Confidential Emissions Plan and Budget for 2017 and 2018[35] discusses forthcoming obligations to comply with several water-related environmental laws, including 316(a) and (b) of the Clean Water Act, as well as the Effluent Limitations Guidelines (ELGs) and the Coal Combustion Residuals (CCR) rule.

Q: Please describe Section 316(a) and 316(b) of the Clean Water Act, as those may affect the costs of keeping the coal units operation.

A: Section 316(a) of the Clean Water Act applies to thermal (heat) wastewater discharges. Thermal discharges can impact the surrounding aquatic environment. Cooling towers reduce thermal discharges by exhausting the waste heat to the air and recycling the cooling water used in the plant, rather than discharging it to the aquatic environment. IPL notes that, if required, these controls would be expensive, and has instead proposed obtaining thermal variances from the Iowa DNR.[36] However, IPL has not obtained thermal variances at this time.

Section 316(b) of the Clean Water Act is targeted at reducing the mortality of aquatic life caused by entrainment (taking in of organisms with cooling water) and impingement (trapping of organisms against the cooling water intake structure. Installation of cooling towers can greatly reduce this

[35] IR 1-SC-14, Confidential Attachment A, Chernick Dir. Confidential Ex. SC-10.

[36] *Id*. at 54-55.

problem. Alternatively, the effects of once-through cooling can be reduced by installing various types of screens to reduce entrainment and impingement. Chernick Dir. Confidential Ex. SC-10. In its Confidential 2017-2018 Emissions Plan and Budget, IPL states that it is considering [redacted] for compliance at [redacted] *Id.* at 64. IPL also notes that it is possible that the IDNR could require IPL to install cooling towers at its facilities to comply with this rule. *Id.* at 60. When asked in this proceeding to confirm whether these control strategies remain IPL's current planned compliance pathway, IPL responded that [redacted]"[37] IPL further stated that "[redacted]." *Id.* IPL also declined to provide a cost estimate for cooling towers at the Lansing facility, if such a control were required. *Id.* at a.ii.1. IPL confirmed that it has not received a thermal variance at the Lansing plant at this time. *Id.* at a.ii.2.

Q: How would the Effluent Limitations Guidelines affect the costs of keeping the coal plants operating?

A: The Effluent Limitations Guidelines increase the stringency of effluent discharge limits in existing Clean Water Act discharge permits. Among other

---

[37] IR 4-SC-1 Confidential (Chernick Dir. Confidential Ex. SC-11).

things, the rule prohibits discharge of pollutants from bottom ash transport water.

According to IPL's publicly-available discharge permit for the Lansing coal plant, IPL is required to convert the existing bottom ash handling system to a dry bottom ash handling system by December 31, 2021.[38] The estimated cost to convert Lansing's bottom ash handling system to a dry bottom ash system is $[redacted]. Chernick Dir. Confidential Ex. SC-11. IPL also states that it would need to install low volume waste water treatment and conduct ash pond outfall re-routing at a cost of $[redacted]. *Id.* IPL has not yet received approvals to begin construction and no construction activities have begun. *Id.*

According to the publicly-available IPL's discharge permit for the Ottumwa coal plant, IPL is required to convert the existing bottom ash handling system to a dry bottom ash handling system by June 1, 2022.[39] The estimated cost to convert Ottumwa's bottom ash handling system to a dry bottom ash system is [redacted] Chernick Dir. Confidential Ex. SC-11. IPL states that it plans to have the new bottom ash handling system in service by June 2020, that it has obtained DNR approvals for construction, and that construction is underway, with $[redacted] already spent. *Id.*

[38] Iowa DNR NPDES Permit #0300100, publicly available through https://programs.iowadnr.gov/wwpie/default.aspx?cmd=SearchPermits

[39] Iowa DNR NPDES Permit #9000101, publicly available through https://programs.iowadnr.gov/wwpie/default.aspx?cmd=SearchPermits

Q: How would the Coal Combustion Residuals rule affect the costs of the coal plants?

A: The Coal Combustion Residuals rule applies to the storage of coal ash waste in landfills, ponds, or impoundments. According to IPL's Emissions Plan and Budget for 2017 and 2018, IPL plans to close one or more existing impoundments at Lansing and Ottumwa. Chernick Dir. Confidential Ex. SC-10 at 71, 74. IPL also states that "all current CCR surface impoundments will require significant upgrades in order to remain open, with "wet ash collection" systems being converted to "dry ash collection" systems. *Id.* IPL also states it plans to [redacted]. *Id.* at 74.

Q: Can you summarize the costs that IPL has identified for Ottumwa and Lansing?

A: Yes. Confidential Table 36 summarizes the information from IRs 1-SC-14, Confidential Attachment A, and 4-SC-1 Confidential. While compliance costs for some requirements are not known, IPL appears to be facing at least $[redacted] in compliance costs for Lansing and $[redacted] for Ottumwa.

Confidential Table 36: Summary of Water-related Retrofit Requirements

Requirement	Lansing		Ottumwa	
	Measure	Cost	Measure	Cost
316(a)		[redacted]		[redacted]
316(b)	[redacted]	[redacted]	[redacted]	[redacted]
ELG	Ash handling conversion, low volume waste water treatment and ash pond outfall re-routing	[redacted]	[redacted]	[redacted]
CCR	Main ash pond closure (2023)	[redacted]	Zero discharge ash pond closure (12/20); low volume wastewater treatment (12/21); main/bottom ash pond closure (12/22)	[redacted]

Retirement of these units before the required compliance dates will avoid some of these costs.

4. *Energy prices and revenue*

Q: To what extent can the IPL coal units vary their output in response to changes in load or market energy prices?

A: In general, large coal units are very slow to respond to changing conditions.

Confidential Table 37 elaborates on the limited load-following abilities of each of the IPL coal units, from IR 1-SC-07 Confidential (Chernick Dir. Confidential Ex. SC-12). The various units have a minimum up time of [redacted] hours and a minimum down time of [redacted] hours. The full plant ramp rate for the units ranges from [redacted] per minute, equivalent to [redacted] of capacity per minute, or [redacted] hours to get from first generation to full power, or back down.

Confidential Table 37: IPL Coal Unit Load-Following Parameters

	Minimum Up Time (Hrs)	Minimum Down Time (Hrs)	Ramp Rate (%/min) up and down	Full Plant Ramp Rate (MW/min) up and down
Burlington	[redacted]	[redacted]	[redacted]	[redacted]
Neal 3	[redacted]	[redacted]	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]	[redacted]	[redacted]
Lansing 4	[redacted]	[redacted]	[redacted]	[redacted]
Louisa	[redacted]	[redacted]	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]	[redacted]	[redacted]

Data source:
Chernick Dir. Confid. Ex. SC-12

The operating limitations of these units do not allow them to follow rapid or large swings in net load. They are poorly suited to operate in the wind-rich system that that is emerging as utilities and other generators add wind capacity (and increasingly, solar capacity) in the Midwest and Plains.

Q: Did IPL provide any confidential data on its dispatch strategy for its coal units?

A: Yes. In response to Board Question No. 5, IPL provided its Planning Assumptions Document, which confidentially revealed that it assumes the [redacted]:

- [redacted].
- [redacted].
- [redacted]

Only the [redacted].

Q: How does IPL explain these requirements?

A: IPL says that Must-Run status may be used where "Mechanical and/or thermal cyclic stress concerns associated with excessive cycling of the unit."

IR 4-SC-2 Confidential (Chernick Dir. Confidential Ex. SC-13). That response also explains IPL's use of the Must-Run status.

> The Must Run commitment status only requires the assets to be online and dispatched to its economic low dispatch limit….
>
> IPL typically uses Must Run status for generating units that [redacted]
>
> For units that IPL Designates as Must Run, [redacted]
>
> MISO only looks ahead one day past the current operating day for economic commitment decisions (day ahead) and does not analyze or quantify the economics of a given unit over a longer period of time.
>
> When IPL forecasts that the [redacted]
>
> Lansing Generating Station – [redacted]
>
> Ottumwa Generating Station – [redacted]
>
> *Id.*

Q: What is the significance of this information?

A: The [redacted] shows that IPL assumes that [redacted] coal plants [redacted]

[redacted] From IR 4-SC-2 Confidential, it is clear that IPL [redacted]

Q: Did IPL provide any confidential forecasts of energy prices?

A: IPL provided long-term projections generated by "Wood Mackenzie's long-term projection of MISO Iowa market energy prices." IR 1-SC-17, Confidential Att. A (Chernick Dir. Confidential Ex. SC-14). Confidential Table 38 below provides IPL's current forecast of the Iowa annual on-peak and off-peak energy prices, along with the Wood Mackenzie forecast of energy prices that IPL used in its [redacted].

Confidential Table 38: IPL Projection of Iowa LMP Forwards $/MWh

	Current Projection		2016 WM Projection		
	On-Peak	Off-Peak	On-Peak	Off-Peak	Annual
	a	*b*	*c*	*d*	*e*
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	
2027	[redacted]	[redacted]	[redacted]	[redacted]	
2028	[redacted]	[redacted]	[redacted]	[redacted]	
2029	[redacted]	[redacted]	[redacted]	[redacted]	
2030	[redacted]	[redacted]	[redacted]	[redacted]	
2031	[redacted]	[redacted]	[redacted]	[redacted]	
2032	[redacted]	[redacted]	[redacted]	[redacted]	
2033	[redacted]	[redacted]	[redacted]	[redacted]	
2034	[redacted]	[redacted]	[redacted]	[redacted]	
2035	[redacted]	[redacted]	[redacted]	[redacted]	
2036	[redacted]	[redacted]			
2037	[redacted]	[redacted]			
2038	[redacted]	[redacted]			
2039	[redacted]	[redacted]			
2040	[redacted]	[redacted]			

Data sources:
a, b: 1-SC-17 Attach A CONF
c, d: IBEC-1, RPU-2016-0005 Attachment C Kitchen Confidential, Chernick Dir. Confid. Ex. SC-15
e: IBEC 65, RPU-2016-0005, Chernick Dir. Confid. Ex. SC-16

Q: How does this energy-price forecast compare to recent forward energy prices?

A: IPL's current forecast is consistent with the forward market prices, through 2023. The 2016 projection was [redacted] current market expectations or Wood Mackenzie's current forecast.

Q: Did IPL provide any estimate of the average price of the energy that would be produced by any of its coal units?

A: Yes. Confidential Table 39 provides the plant-specific LMPs used in IPL's [redacted], which was provided IBEC IR 61, Confidential Attachment B, from RPU-2016-0005, Chernick Dir. Confidential Exhibit 17. These prices are much higher than the LMPs that those plants have earned in recent years.

Confidential Table 39: Plant-specific LMPs Assumed By IPL in 2016

	2020	2023
Neal 3	[redacted]	[redacted]
Neal 4	[redacted]	[redacted]
Lansing 4	[redacted]	[redacted]
Louisa	[redacted]	[redacted]
Ottumwa	[redacted]	[redacted]

Q: What is the significance of these 2016 estimates of energy prices?

A: These energy prices are from Wood Mackenzie's 2H2015 forecast, and are [redacted] (1-SC-22, Confidential Attachment A, p. 15) [redacted] (for which we have seen only a graph (ibid.) and not tabular values) [redacted]. Hence, the analysis in 1-SC-22, Confidential Attachment A overstates the benefit of the future [redacted] and cannot justify its continued operation.

5. *Capacity prices*

Q: What market capacity prices does IPL assume?

A: IPL provides a forecast of capacity revenues in its [redacted] (IR 1-SC-24 Supp Confidential, Confidential Attachment B, tab "Capacity Value Inputs") in millions of dollars, as well as IPL's current forecast of MISO Zone 3 Iowa capacity prices, from [redacted] (IR 1-SC-17, Confidential Attachment A). Confidential Table 40 presents IPL's [redacted] projection, the conversion of those revenues to $/kW-year prices using [redacted] accredited capacity of [redacted] MW, the current capacity price projection, and annual growth rate for both forecasts, and the actual prices for 2018 and 2019.

Confidential Table 40: IPL Forecast of MISO Zone 3 Iowa Capacity Price

	From 1-SC-24 CONF			From 1-SC-17 CONF		Actual
Year	**$M**	**$/kW-year**	**Annual Increase**	**$/kW-year**	**Annual Increase**	**$/kW-year**
2018	[redacted]	[redacted]				$3.7
2019	[redacted]	[redacted]	[redacted]	[redacted]		$1.1
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

IPL's forecast of capacity price from 1-SC-24 Confidential was about [redacted] times the actual price for 2018 and about [redacted] the actual price for 2019. The forecasts for those two years were [redacted] and [redacted] the average price over the six years of the MISO capacity market. In 1-SC-17 Confidential, the IPL forecast for 2019 had declined, but was still about [redacted] the actual price. In both forecasts, IPL projected that capacity prices [redacted] in the first several years. The forecast prices in 1-SC-17 Confidential grow [redacted] than those in 1-SC-24 Confidential. Both forecasts assume that prices will [redacted]. These projections appear to be [redacted].

Q: Please summarize the effect of IPL's confidential data on your conclusions in Section III.

A: IPL's confidential data and assumptions reinforce my conclusions from public data. The assumptions underlying IPL's internal evaluation of continued coal-plant operation were optimistic; more realistic assumptions would lead to the conclusion that the plants should be retired.

V. Costs of Renewables

Q: Has IPL provided you with any information on wind PPAs?

A: Yes. In IR 1-SC-09 Confidential (Chernick Dir. Confidential Ex. SC-18), IPL provided what it said were "IPL's utility-scale wind PPAs, with the starting contract price for 2020." Confidential Table 41 lists the name, time period, and price for each PPA. I have added the commercial operation date (where I have been able to match the name used in 1-SC-09 to other sources), from the EIA Form 860 and from 1-SC-22, Conf. Attachment A, p. 7, which identifies the [redacted]. For the new contracts, the prices are $[redacted]/MWh (for [redacted]) or $[redacted]/MWh (for the other facilities), [redacted] over [redacted] years.

Confidential Table 41: IPL Wind PPAs in 2020

Power Purchase Agreement	Time Period	PPA Price ($/MWh)	COD
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	

Q: How do IPL's wind PPA prices compare to other PPAs?

A: Table 42 shows levelized PPA prices for wind power in the northern MISO regions, as compiled by LevelTen Energy for Q3 2018 to Q2 2019.[40] Pricing for the Minnesota and Illinois hubs are included in the table since these hubs overlap northern and southern Iowa, respectively. Table 42 also shows the levelized prices for utility-scale solar projects. The PPA prices in the table refer to the most competitive 25th percentile offer prices associated with projects with contract tenors of 10 to 25 years. LevelTen does not publish all combinations of locations and contract start dates.

[40] https://leveltenenergy.com/.

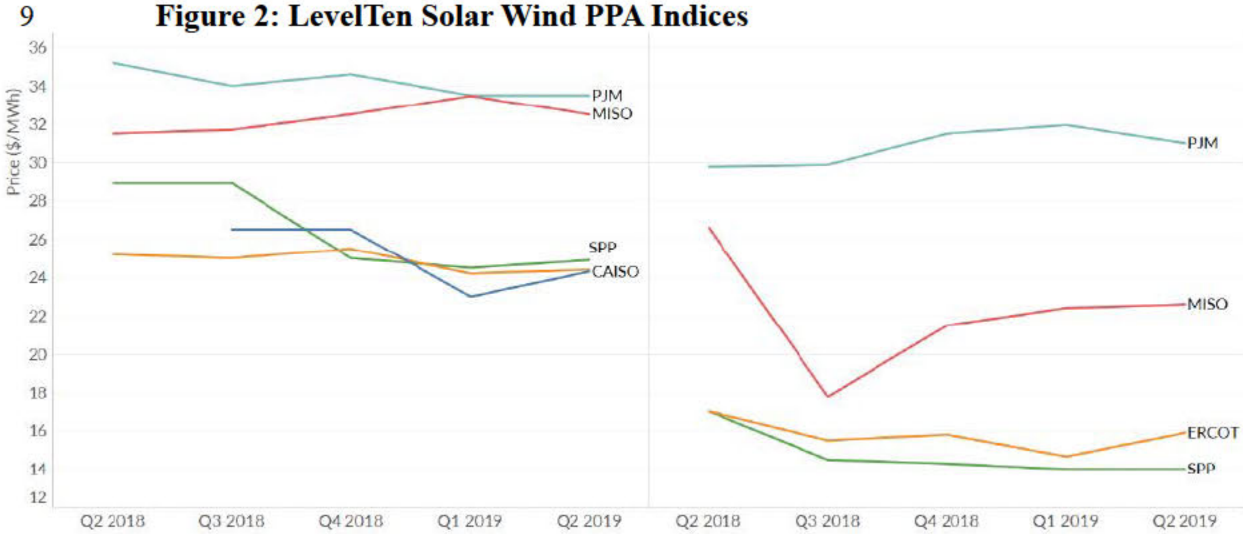
Table 42: LevelTen Energy Levelized MISO P25 PPA prices

	Region	Wind PPA Price ($/MWh)	Solar PPA Price ($/MWh)
Q3 2018	Minnesota	$17.4	NA
	Illinois	$27.0	NA
Q4 2018	Minnesota	$20.0	$34.2
	Illinois	$26.9	$35.1
Q1 2019	Minnesota	$20.7	$34.6
	Illinois	$21.8	$39.5
Q2 2019	Minnesota	$15.7	$34.2
	Illinois	$21.8	$34.7

The average price for IPL's 2019 and 2020 wind PPAs ($[redacted]) [redacted] the levelized prices LevelTen reports for each of the previous four quarters.

Figure 2 below shows the levelized MISO solar and wind PPA price trajectories by ISO over the past few quarters. LevelTen describes these data as price indices; the prices are higher than the P25 values, and may represent median prices.

Figure 2: LevelTen Solar Wind PPA Indices



Q: How much capacity credit does MISO give for solar and wind resources?

A: For MISO's most recent planning year, 2019-2020, the capacity credit for wind generation was set at 15.7%, which translated to 2,855 MW out of 18,210 MW of unforced wind capacity potentially qualifying under Module E-1 of MISO's tariff. The 2019-2020 wind capacity credit is 0.5 percent points higher than the 2018-2019 credit. While MISO consistently assumes that wind's capacity credit will decline as penetration rises, its estimate of the capacity contribution has increased over 20% since 2011, even as wind penetration has nearly doubled.[41] The default solar capacity credit for the 2019-2020 planning year remains at 50%.[42]

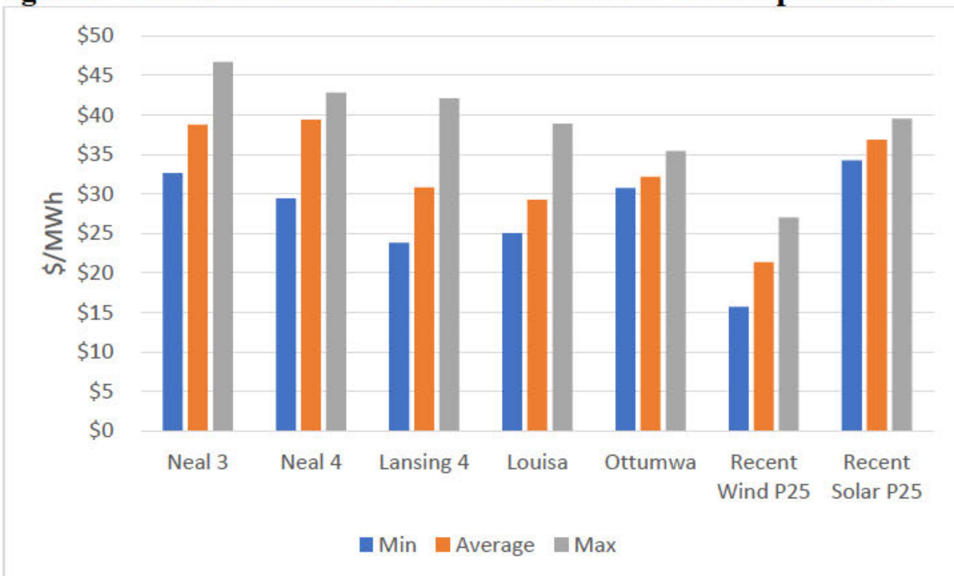
Q: How do these costs of renewables compare to the costs of continuing to operate IPL's coal resources?

A: Figure 3 compares the costs of continuing to run the coal resources with the costs of recent renewable PPAs. For each coal resource, I present the lowest annual $/MWh cost, the average cost, and the maximum cost, for 2013–2018, from Table 12. For renewables, I present the minimum, average and maximum costs of the Minnesota and Illinois PPA for the past four quarters, from Table 42.

[41] MISO Planning Year 2019-2020 Wind & Solar Capacity Credit, December 2018, p. 9.

[42] Ibid., p. 3. [redacted] (DR 1-SC-24 SUPP CONF Table 3)

Figure 3: Costs of Renewable PPAs and IPL Coal Plant Operation



As Figure 3 shows, the low wind price is lower than the low cost for each coal unit, the average wind price is lower than the average cost for each coal unit, and the high price is lower than the high cost for each coal unit. The high wind price is lower than the low annual coal cost for both Neal units and Ottumwa. With gross capital additions, rather than the net capital additions in Table 12, the costs of continuing to run the coal plants would be even higher.

The high solar price is lower than the high cost year for both Neal units and Lansing, and the average solar price is lower than the average year for both Neal units. Since a solar plant provides more energy in the high-value on-peak period, and provide an unusually large amount of capacity per unit of energy, it may be cost-effective even if its energy price were somewhat higher than the cost per MWh of a coal plant.

Q: How much could ratepayers save if the coal units were placed with wind energy?

A: Just comparing the costs of energy, customers would save about $44 million annually replacing $30/MWh coal with $20/MWh wind energy, over the 4,400 GWh reported for IPL's share of Neal, Lansing, Louisa and Ottumwa in IPL's 2018 FERC Form 1. Since this change in resources would change the dispatch of IPL's system into the MISO market, the overall effect of the transition would be somewhat different from this top-level estimate.

VI. Other Studies of Coal-Plant Economics

Q: Have other recent studies reviewed the prospects for economic coal plant operation?

A: Yes. Bloomberg New Energy Finance (BNEF), the Brattle Group and the Coal Tracker Initiative released conducted separate analyses of coal-plant cost-effectiveness in 2018.

A. The BNEF Study

Q: What did the BNEF study examine?

A: The Bloomberg study, attached as Chernick Dir. Ex. SC-19, covered the six-year period of 2012 through 2017, for 903 units totaling 280 MW of nameplate capacity, excluding combined heat and power units.[43] The authors compared energy, capacity and byproduct revenues by unit to the fuel, variable O&M and emissions charges, to compute what they call the "short-run margin." Adding fixed O&M to the costs produces the "long-run

[43] Half of U.S. Coal Fleet on Shaky Economic Footing: Coal Plant Operating Margins Nationwide, William Nelson and Sophia Liu, March 26, 2018.

margin." The study reports environmental capital additions, but does not include any capacity additions in the profitability analysis.

Q: What did the BNEF study conclude?

A: The study's conclusions included the following:

> By our estimates, 48% of the coal fleet (135 of 280 GW) posted negative margins from 2012-17…
>
> We find ourselves awestruck by the resilience of U.S. coal. Plants persist even when they cost more to run than replace. As we hunt for coal closures, beware of the sometimes tenuous link between 'economics' and 'retirement decisions'. The link is especially weak in regulated regions, where high-cost coal runs regularly out of merit. …
>
> The majority of 'uneconomic' units (130GW of 135GW) are regulated. They are kept online by virtue of cost-plus pacts that partially insulate owners from shifting economics. … (p. 1)
>
> Coal plants were originally designed to run baseload – to sell large volumes of electricity with healthy short-run operating margins (i.e. dark spreads). This was necessary to cover relatively high fixed costs. Since the shale boom, collapsing dark spreads and dwindling capacity factors have cut deeply into coal's energy revenues – so much so that plants sometimes fail to cover fixed operating costs. Ongoing operating losses can drive plants to retire.
>
> Simply boosting output is not an option. Plants have reduced their capacity factors precisely because in many hours, fuel prices are higher than power prices. Running more would mean running at a loss. (p. 8)

Q: What does BNEF conclude about IPL's plants?

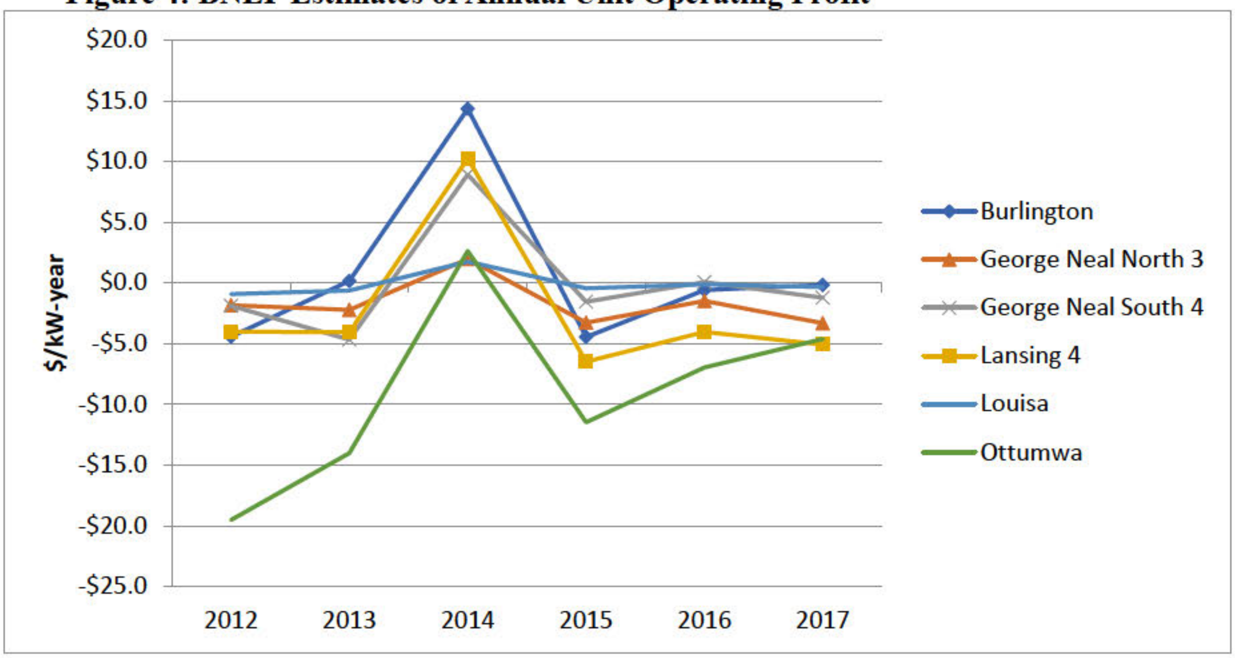
A: Table 43 provides BNEF's results for each of the IPL units, for each year and cumulative for the period. BNEF estimates that all of the units lost money in five of the six years, with five of the six units losing money overall. Burlington ended the period with a slight operating profit, but only because of a very good year in 2014.

Table 43: BNEF Estimates of IPL Unit Operating Profit ($/kW)

	2012	2013	2014	2015	2016	2017	Total
Burlington	-$4.4	$0.2	$14.3	-$4.5	-$0.6	-$0.2	$4.9
Neal North 3	-$1.8	-$2.2	$2.0	-$3.3	-$1.5	-$3.3	-$10.2
Neal South 4	-$1.9	-$4.7	$8.9	-$1.6	$0.1	-$1.2	-$0.3
Lansing 4	-$4.0	-$4.1	$10.3	-$6.5	-$4.0	-$5.1	-$13.4
Louisa	-$0.9	-$0.6	$1.8	-$0.4	-$0.1	-$0.3	-$0.7
Ottumwa	-$19.5	-$14.0	$2.6	-$11.5	-$7.0	-$4.6	-$54.0

Figure 4 presents the annual data from Table 43 in graphical format.

Figure 4: BNEF Estimates of Annual Unit Operating Profit



Since these are the annual operating profits without capital additions or overheads, these results understate the losses that IPL's customers have experienced, especially from Lansing, Ottumwa, and Neal 3. Including capital additions and overheads, the losses on those units would be even larger, as demonstrated in Section III, above.

B. The Brattle Study

Q: What were the results of the Brattle study?

A: The Brattle Group study, attached as Chernick Dir. Ex. SC-20, used ABB's Velocity Suite data (the default data for PROMOD) to estimate the 2017 net margin for each domestic coal plant (as well as each nuclear plant).[44] Brattle does not identify the results for specific units, but does provide aggregate results, as summarized in Table 44.

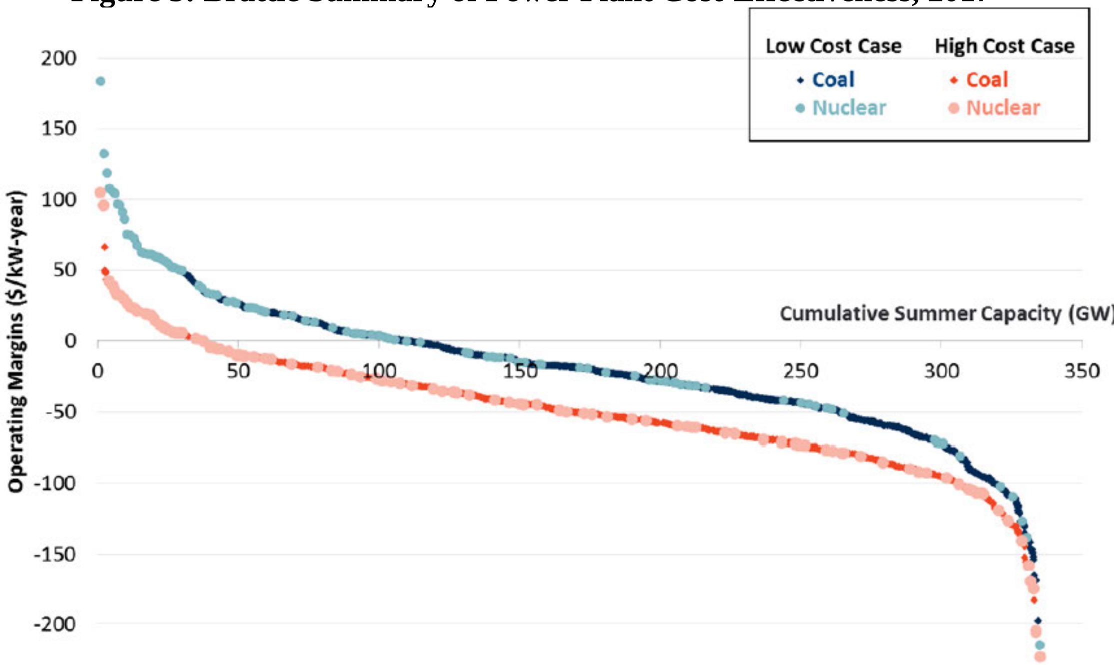
Table 44: Brattle Results for Coal Plant Economics, 2017

		Capacity with Revenue Shortfall			
		Gigawatts		Percentage of Total	
	Total Capacity (GW)	Low-Cost Case	High-Cost Case	Low-Cost Case	High-Cost Case
RTO	160.1	120.1	154.2	75%	96%
Non-RTO	75.7	65.3	69.5	86%	92%
Total	235.8	185.4	223.7	79%	95%

Brattle also plotted the distribution of plant profitability, as shown in Figure 5.

[44] The Cost of Preventing Baseload Retirements: A Preliminary Examination of the DOE Memorandum, Metin Celebi, et al, July 2018. Brattle reports that it excluded another 11.7 GW of coal units (averaging 37 MW per unit) were listed as having no generation and in most cases no cost data.

Figure 5: Brattle Summary of Power Plant Cost-Effectiveness, 2017



The dark data points, representing the coal plants, are sometimes obscured by the large light data points that Brattle used for the nuclear units.

Q: How do the costs of the coal units in the Brattle analysis compare to the costs of the IPL coal units?

A: The average costs of the coal units in the Brattle analysis are listed in Table 45. Brattle used the unit-specific fuel and VOM costs from the ABB database, generic FOM values from EPA and capital additions (CapEx) costs from EIA.

Table 45: Brattle Average Coal Forward Costs ($/MWh)

	Low-Cost Case	High-Cost Case
Fuel Costs	$22.30	$22.30
VOM	$1.56	$4.91
FOM	$7.14	$8.51
Ongoing CapEx	$4.97	$4.97
Total	$35.97	$40.69

The costs of the IPL coal units, summarized in Table 12, generally fall in the range of the Brattle average costs. And the average unit in the Brattle analysis is uneconomic.

VII. Recommendations

Q: What are your recommendations?

A: IPL should plan for the retirement of all its coal resources, timed to minimize the losses of continued operation and to avoid any major capital expenditures.[45] Ottumwa and Neal 3 and 4 look particularly uneconomic, but Lansing should also be retired as soon as feasible, and in time to avoid additional environmental compliance cost obligations. While Louisa is uneconomic, and IPL should press MidAmerican to minimize the continued cost of running the plant, it appears to be the least uneconomic of IPL's coal plant ownership interests.

In support of the retirement of these units, IPL should start (in conjunction with MidAmerican for the jointly-owned units) the process of determining how transmission constraints, reliability, or other considerations will shape IPL's choice and location of replacement resources. IPL should also be thinking about the cost-recovery timing and ratemaking for the retired units, so that customers are not excessively burdened by recovery of prudently-incurred costs, especially as IPL is recovering the front-loaded costs of recent ratebase additions.

[45] Burlington and the Prairie Creek units are already required to retire or convert to gas.

To replace these retiring coal plants, IPL should be procuring a mix of market purchases, wind, and central and distributed solar and storage, as well as improving customer end-use efficiency and encouraging demand-response resources that allow IPL to shift load out of hours with high loads, low regional wind and solar production, and high costs. In selecting the replacement resources, IPL should strive to minimize ratepayer costs and risks. Where a resource type can be developed and/or owned by both IPL and third parties, IPL should compare the costs of building the resources itself; contracting for a third party to build and operate the resources, eventually transferring ownership to IPL; and conventional power-purchase agreements (PPAs), in which the third party builds, owns and operates the facility. The least-cost and least-risk option may vary among projects.

Q: Do you have any recommendations for the Board?

A: Yes. The Board should find that IPL would be imprudent to continue incurring avoidable future capital and operating costs for its coal resources and that the resulting costs would not be in the public interest. The Board should put IPL on notice that it will disallow cost recovery for such discretionary future expenditures.[46] Finally, Board should support any efforts that IPL undertakes to prepare for the retirement of the uneconomic units.

Q: Does this conclude your testimony?

A: Yes.

[46] Discretionary and avoidable spending would include capital additions (including environmental retrofits) necessary to continue operate the units, as opposed to costs required to remediate existing safety and environmental problems.

AFFIDAVIT

I, Paul Chernick, being first duly sworn on oath, state that I am the same Paul Chernick identified in the testimony being filed with this affidavit, that I have caused the testimony and exhibits to be prepared and am familiar with its contents, and that the testimony and exhibits are true and correct to the best of my knowledge and belief as of the date of this affidavit.

*/s/ Paul Chernick*___________

Paul Chernick

Subscribed and sworn to before me,
a Notary Public in and for said County
and State, this 31st day of July, 2019.

/s/Dianne Demarco____________
Dianne Demarco
Notary Public
My commission expires on ____9/11/2020____________