SIERRA CLUB

September 4, 2018

VIA HAND DELIVERY
Ms. Terri Bordelon
Louisiana Public Service Commission
Records Division
602 N. Fifth St.
Galvez Bldg, 12th Floor
Baton Rouge, LA 70802

Re: LPSC DOCKET NO. U-34794, In RE: Application of Cleco Corporate Holdings LLC and Cleco Power LLC for: (i) Authorizations, Waivers, and Regulatory Interpretations or Certain Provisions of LPSC Order No. U-33434-A; (ii) Authorization for Cleco Corporate Holdings LLC to Pledge its Ownership Interest in Cleco Power LLC; and (iii) Expedited Treatment

Dear Ms. Bordelon:

Enclosed please find a find one (1) original and two (2) copies of a **public version** of the Direct Testimony of Paul Chernick on behalf of Sierra Club. A public version of Exhibit PLC-2, which excludes Data Request Responses designated as HSPM, has been filed with the public version of the testimony.

Further enclosed, in a sealed envelope, please find one (1) original and two (2) copies of a confidential version of the Direct Testimony of Paul Chernick on behalf of Sierra Club containing information designated as **HIGHLY SENSITIVE PROTECTED MATERIALS PURSUANT TO THE CONFIDENTIALITY AGREEMENT IN DOCKET NO. U-34794**. Exhibit PLC-2 in full has been filed under seal as it contains material designated as **HSPM**. Please also refer to the two flash drives sent separately via federal express for **HSPM** attachments to PLC-2. If you have any questions, please do not hesitate to contact me.

Sincerely,

Joshua Smith
Sierra Club
2101 Webster Street, Suite 1300
Oakland, CA 94612
joshua.smith@sierraclub.org
415-977-5560

STATE OF LOUISIANA

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Application of Cleco Corporate Holdings LLC and Cleco Power LLC for: (I) Authorizations, Waivers, and Regulatory Interpretations of Certain Provisions of LPSC Order No. U-33434-A; (II) Authorization for Cleco Corporate Holdings LLC to Pledge its Ownership Interest in Cleco Power LLC; and (III) Expedited Treatment.	**)))))))))**	**Docket U-34794**

DIRECT TESTIMONY OF PAUL CHERNICK ON BEHALF OF SIERRA CLUB

PUBLIC VERSION

Resource Insight, Inc.

SEPTEMBER 4, 2018

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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 Exhibit PLC-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.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Sierra Club.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to determine whether the proposed transaction would negatively impact Cleco Power LLC ("Cleco Power") and its retail customers. In Phase I of this complex transaction, Cleco Power's parent company, Cleco Corporate Holdings LLC ("Cleco Corp") proposes to purchase from NRG South Generating LLC ("NRG") certain power plants in Louisiana and Texas, which Cleco Corp would transfer to a newly formed subsidiary, Cleco Cajun; lease back one of those plants to NRG (which would continue to operate it), and transfer to Cleco Cajun a set of limited-duration wholesale contracts, mostly requirement sales to electric cooperatives.[1] Specifically, my testimony analyzes: (1) the economic value of the NRG generation resources; (2) the value of the contracts; and (3) the economic soundness of selected Cleco Power resources, to determine (a) whether those resources should be retired, increasing Cleco Power's need for a large capital infusion to replace those resources, and (b) whether any of the costs and risks of the proposed transaction might be mitigated by retiring the

[1] NRG owns additional generation in the Gulf Coast region and elsewhere. My references to the NRG resources is limited to the units included in the proposed transaction. I sometimes refer to Cleco Corp and its affiliates as "Cleco," where there is no meaningful ambiguity.

uneconomic coal plants and using the best of NRG's resources to serve Cleco Power ratepayers.[2]

Q: How does this proposed transaction affect Cleco Power?

A: Cleco Corp proposes to purchase about 3,555 megawatts of generation capacity and several wholesale power contract obligations for $1 billion, which would be raised from $550 million in debt and $450 million in equity. Since Cleco Power is a privately held utility, it is completely reliant on its parent company, Cleco Corp, for any equity required to provide safe, reliable, and least-cost service to its ratepayers. If Cleco Corp over-extends its financial position, Cleco Power could be directly impacted by losing access to equity, having to pay a higher premium for debt, and/or (if Cleco Corp became insolvent) enduring a prolonged period of financial and operational uncertainty and coming under new ownership.[3] The interests of Cleco Corp's owners would also create pressure for transfer of uneconomic

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[2] The economics of the Cleco Power coal plants are also relevant to assessing Cleco's claim that the Phase I transaction reflects Cleco Corp's continuing commitment to optimizing its Louisiana electric system infrastructure, and its suggestion that integration of the Big Cajun 2 coal units would improve the operation of the Cleco Power fleet. Application at 6, 22. Both the Cleco Power and NRG coal units are uneconomic and there is no reason to suppose that having them all owned by Cleco Power would make them economic.

[3] Cleco Power's bond ratings and access to debt capital are influenced by Cleco Corp's financial condition. These issues are discussed in more detail in the testimony of Sierra Club witness Scott Hempling.

generation or purchase obligations to Cleco Power. If a later Commission were to approve the transfer of all the Cleco Cajun resources to Cleco Power in Phase II, Cleco Power customers would be burdened with uneconomic resources. Thus, the Applicants' proposal carries significant risks for Cleco Power customers.

Q: Please describe in more detail your concerns with the proposed transaction.

A: Cleco Corp has put forth an analysis that purports to demonstrate that this transaction is worth $1 billion, at least from the perspective of Cleco Corp's owners.[4] Despite the amount of money involved and the risks inherent in such a transaction, Cleco has refused to provide support for most of its assumptions of costs and revenue. Even under Cleco Corp's own unsupported assumptions, most of the generation it would be purchasing are unprofitable or marginally economic, even if Cleco Corp were not paying a dime for them. Indeed, based on my evaluation, the NRG coal units (Big Cajun 2, Units 1 and 3) are significant economic losers; Cleco's own data

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[4] This analysis, provided in Response to LPSC 3-14, Attachment A, actually assumes a purchase price of $[redacted] million and does not present any specific computation of net benefits or return. I cannot determine what economic test the Cleco Corp investors applied in determining that the deal would be advantageous to them.

For ease of reference, I use abbreviations to refer to the Applicants' responses to Data Requests. For example, the Applicants' response to the Louisiana Public Service assumptions indicate that those units would cost more to run than they earn in the MISO energy markets, losing $[redacted] million cumulatively from 2019 through 2025, compared to not operating the resources.[5] The losses from operating Big Cajun 2 Units 1 and 3 are so large that the owner could cease operating both units now, continue to pay *all* of the workers' salaries and property taxes through 2025, and still save approximately $[redacted] million.[6] The gas steam units at Big Cajun 1 and Big Cajun 2, Unit 2, as well as the Sterlington combustion turbines are also uneconomic under Cleco's own assumptions, but less so than the coal units.[7] Any deterioration of the economics of these plants—such as from higher O&M, unexpected equipment repairs and replacement, lower availability, or lower energy prices compared to Cleco's projections—would further erode Cleco Corp's financial position. In the best case, Cleco Corp would be acquiring several

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Commission Staff's Data Request 3-14 is identified as "Response to LPSC 3-14." Exhibit PLC-2 contains copies of the relevant Data Responses to which I cite.

[5] All of the costs reported in this study are in nominal dollars, with the exception of a couple of $/kW-year values that I cite from generic studies; those are labeled with the year for which they are stated (e.g., "2016$").

[6] I calculated this estimate by subtracting the total payroll and property tax costs Cleco provided in Response to LPSC 3-14, Attachment A, from the total losses, as described below.

[7] Sterlington is also [redacted] with a substantial share [redacted].

resources that are substantial liabilities as operating assets, with uncertain costs of environmental remediation.

The seven or so remaining years of the cooperative contracts are priced above the cost of MISO purchases to serve the contracts, and should generate some profit, but they are not valuable enough to offset the drain of this uneconomic generation fleet and repay the billion-dollar purchase price. Cleco's forecast of sales under the existing and hypothetical contracts assumes load growth that is inconsistent with the historical record. Moreover, Cleco's assumptions about contract renewal—that [redacted]% of the coop contracts will be renewed at a contract price that is far above market energy prices—are undocumented and unreasonable.[8] Of the seven long-term contracts that NRG acquired with the Big Cajun plants that have expired, only two of the purchasers have renewed. In the competitive MISO wholesale market, the cooperatives should be able to acquire power at the MISO market prices (plus some fees to a power marketer, if the cooperatives do not wish to manage their own portfolio).

[8] Response to LPSC 3-14, Attachment A.

Q: Has Cleco Corp demonstrated that is committed to minimize the costs and risks of the transaction?

A: No. Cleco's most detailed presentation (in Response to LPSC 3-14) shows it paying off only about $[redacted] million of the debt through 2025.[9] If Cleco's assessments of the value of the contracts and Cottonwood are overstated, Cleco Corp risks being unable to repay the transaction debt or raise the capital that Cleco Power will require to provide safe and reliable service.

Cleco Power will probably need equity infusions in the next few years to provide safe and reliable power to its customers, for routine upgrades, storm repairs and replacement of Cleco Power's uneconomic and obsolete generation resources. Indeed, as demonstrated below, Cleco Power's existing, solid-fuel generation fleet is currently uneconomic and a significant burden on ratepayers. This transaction increases the risk that Cleco Power's parent company will not be able to access additional equity required to replace Cleco Power's aging and uneconomic plants. In addition, the Commission may be pressured to integrate uneconomic Cleco Cajun assets

[9] Two business days before this testimony was due, Cleco provided a new schedule of debt payments, without any connection to assumed revenues, costs or other cash flows (Supplemental Response to LPSC 6-1). That document shows Cleco paying off only $[redacted] million of the new debt. (The document shows other information, whose relevance has not been explained.)

into Cleco Power's rate base or approve contracts burdening jurisdictional ratepayers uneconomic purchases from Cleco Cajun.

Those risks can be avoided in two ways: either rejecting the Application or conditioning approval on prompt retirement of the Big Cajun 2 coal units and Cleco Power's coal units, followed by further evaluation and optimization of the combined Cleco Power and Cleco Cajun resource portfolio.[10]

Q: How are the Cleco Power generation assets relevant to the scope of this proceeding?

A: They are relevant for at least three reasons. First, the Applicants have asserted that this transaction benefits Cleco Power ratepayers by "reflect[ing] the owner group's continuing commitment to invest in the development and optimization of Louisiana's electric infrastructure…."[11] Most of the Cleco Cajun resources are uneconomic, as are the Cleco Power coal units. Any meaningful definition of "optimizing" Louisiana's electric infrastructure would require retirement and replacement of those resources. An analysis of

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[10] The integrated resource plan ("IRP") process is generally the appropriate mechanism for making retirement decisions, but based on my analysis, the Big Cajun 2 coal units are so uneconomic that they impose an unacceptable risk on the Cleco enterprise. In any event, any objective IRP would conclude that those units should be retired.

[11] Application at 6, 22; Direct Testimony of Shane Hilton at 12.

the viability of the existing Cleco Power assets is central to the Commission's determination as to whether Phase I reflects a continued effort to optimize Louisiana's electric infrastructure.

Second, as my analysis demonstrates, much of Cleco Power's existing solid-fuel fleet is uneconomic, requires capital improvements, and is at risk of retirement. The financial burdens associated with this transaction create a risk that Cleco Corp will not be able to access or provide the additional equity that may be required to replace Cleco Power's aging and uneconomic generation, in addition to normal capital requirements and the occasional emergency.

Third, while my primary recommendation is that the Commission deny the Application, if the Commission is nonetheless inclined to approve the transaction, my alternative recommendation is that the approval include conditions to benefit the ratepayers. Ensuring ratepayer benefits would require pruning the worst-performing resources from the portfolio, identifying the cost-effective portion of the NRG portfolio (such as Cottonwood and Bayou Cove) and determining how those resources might be used to improve the Cleco Power supply mix, by replacing the uneconomic Cleco Power coal-fired plants, reducing costs to ratepayers. Hence, I suggest that any approval be conditioned on the prompt retirement of Big Cajun 2, Units 1 and 3, Dolet Hills, and Rodemacher, followed by an integrated resource plan ("IRP") that looks at its generation needs and whether some of the NRG fleet best meets those needs.[12] If this analysis shows that some combination of these two fleets provides optimization then, and only then, should the Commission authorize an acquisition.

Q: How is the rest of your testimony structured?

A: The remaining subsections in **Section II** provide some background regarding the proposed and planned transactions and summarize my conclusions and recommendations. **Section III** provides a detailed review of the economic value of the NRG generation resources, including the analysis submitted by Cleco itself to support this application (which indicates that most of the units it intends to purchase are uneconomic, some by stunningly large margins), and the publicly available data on the recent operational, cost and revenue history of the NRG plants. **Section IV** discusses the profitability of the wholesale contracts that NRG hold with the various cooperatives ("coops") and municipal utilities ("munis"). **Section V** provides data on the recent operational and cost history and the historical energy and capacity prices

[12] Ideally, this would involve a fully reviewable IRP, developed with stakeholder input, and focused on the questions related to opportunities for eliminating the least economic resources, such as advancing the availability of the Bayou Cove and Cottonwood plant to Cleco Power customers, procuring renewable resources. If important decisions need to be taken before a full IRP can be conducted, a more narrowly focused analysis may suffice.

received by various Cleco plants, especially the uneconomic coal units. **Section VI** provides information from other studies of coal-plant profitability and retirements. **Section VII** briefly summarizes all of my findings.

Q: Please summarize your conclusions.

A: As described in the testimony of Scott Hempling, the transaction's total cost and financing of the transaction would expose Cleco Corp to significant risk. Since Cleco Corp is Cleco Power's sole source of equity for necessary investments, that risk flows to Cleco Power and its customers.

Historical data show that the NRG coal resources have been uneconomic in recent years, and Cleco's own forecasts indicate that most of the generation that Cleco would acquire will continue to be uneconomic to operate. Even if all goes according to Cleco's projections, Cleco would be saddled with operating losses from those units throughout their lives. Initially, those losses would erode Cleco Corp's financial strength, which can have indirect effects on Cleco Power's costs. Those losses could directly increase rates for Cleco Power customers, if Cleco Corp succeeds in transferring those uneconomic units to Cleco Power and the Commission allows Cleco Power to recover the costs. The majority of the resources that Cleco proposes to purchase and eventually transfer to Cleco Power are worth less than nothing, and would impose additional decommissioning and cleanup costs. Even if Cleco Cajun offered the resources to Cleco Power for free, the ratepayers would not benefit from acquiring them.

Any unexpected costs at the acquired units would increase the burden on Cleco Corp and Cleco Power. If problems with the acquired resources were to force Cleco Corp into bankruptcy restructuring, ownership or Cleco Power and the Commission's control over Cleco Power's rates could be in doubt.

Cleco makes optimistic, and even unrealistic, assumptions about the revenues and longevity of the long-term wholesale contracts. More realistic assumptions would show lower benefits from the remaining period of the contracts and essentially no benefit thereafter.

The transaction as a whole is unlikely to benefit Cleco Power's retail customers. It is much more likely to harm those customers.

Q: How can the Commission avoid the adverse consequences of the proposed transaction?

A: As I see it, the Commission has two options. First, it can simply reject the Application. Alternatively, the Commission can condition approval of the transaction on the prompt optimization of the combined Cleco generation fleet. My analysis indicates that optimization would include prompt retirement of the Big Cajun coal-fired units, plus Cleco Power's Dolet Hills and Rodemacher, followed by regulatory review of the economics of the remaining acquired units and Cleco Power's Madison unit.[13]

Q: How would retirement of the Big Cajun coal units affect the cooperatives?

A: The retirement of these units would probably have little effect on the prices paid by the cooperatives. The cooperatives pay energy charges that in various ways reflect (among other things) the price of [redacted] and in some cases the price of [redacted].[14] Other charges are [redacted]. In the event of retirement of (or [redacted] at) both Big Cajun 2 Units 1 and 3, the parties would need to renegotiate the [redacted] provision in the coop contracts.

At one extreme, if the long-term contracts were terminated, the cooperatives would wind up paying much less for power at market prices than they are paying under the contracts. The cooperatives' Louisiana

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[13] As noted above, in an ideal world the Commission would not issue an order on this Application until after, Cleco developed a fully reviewable IRP, with stakeholder input, and focused on the questions related to opportunities for eliminating the least economic resources, such as advancing the availability of the Bayou Cove and Cottonwood plant to Cleco Power customers and procuring renewable resources. Sometimes decisions must be made on a compressed timeframe, so I have made specific recommendations that will unquestionably improve Louisiana's generation mix.

[14] The contracts use [redacted], with some pricing options within the forms. *See generally* Attachments to Response to LPSC 1-22.

customers would be better off without the present contracts, buying power at market prices, from Cleco, Entergy or other parties.

A. Background

Q: Please describe the proposed transaction.

A: A set of NRG subsidiaries would sell a total of about 3,555 MW at 23 units to Cleco Corp. Those resources would be owned by a subsidiary tentatively named Cleco Cajun, which would also acquire a set of long-term wholesale contracts currently held by NRG subsidiaries, and would lease the Cottonwood combined-cycle plant back to NRG through 2025. Cleco's financial projections assume that Cleco Cajun would transfer some (or perhaps all) of the generation resources and/or wholesale contracts to Cleco Power in a future Phase II proceeding, where their operating costs and potentially some capital costs would be borne by ratepayers.

1. The NRG Units

Q: Which generation resources would NRG transfer to Cleco Corp?

A: Table 1 lists the resources that would be transferred from various NRG subsidiaries to Cleco Cajun. Data are from the EIA Form 860 database.[15]

[15] *See* https://www.eia.gov/electricity/data/eia860/. Utilities, including Cleco and NRG, self-report fuel, energy generation, and sales data, among other information, to the U.S. Energy Information Administration ("EIA"), which then disseminates that information publicly.

Table 1: NRG Generation Resources Proposed for Sale to Cleco Cajun

Plant	Unit	Type	Fuel	COD	MW	NRG %	NRG MW	Forced Outage Rate
Bayou Cove	2	GT	Gas	2002	75	100%	75	[redacted]
	3	GT	Gas	2002	75	100%	75	
	4	GT	Gas	2002	75	100%	75	
Sterlington	1	GT	Gas		24	100%	24	[redacted]
	2	GT	Gas		22	100%	22	
	3	GT	Gas		22	100%	22	
	4	GT	Gas		23	100%	23	
	6	GT	Gas		18	100%	18	
	7	GT	Gas		16	100%	16	
	8	GT	Gas		19	100%	19	
	9	GT	Gas		16	100%	16	
	10	GT	Gas		16	100%	16	
Big Cajun 1	1	ST	Gas	1972	110	100%	110	[redacted]
	2	ST	Gas	1972	110	100%	110	
	3	GT	Gas	2001	105	100%	105	
	4	GT	Gas	2001	105	100%	105	
Big Cajun 2	1	ST	Coal	1981	580	100%	580	[redacted]
	2	ST	Gas	1982	575	100%	575	[redacted]
	3	ST	Coal	1983	588	58%	341	[redacted]
Cottonwood	1	CC	Gas	2003	295	100%	295	[redacted]
	2	CC	Gas	2003	295	100%	295	
	3	CC	Gas	2003	295	100%	295	
	4	CC	Gas	2003	295	100%	295	

Unit types: GT = gas turbine; ST = steam; CC = combined-cycle
Data from EIA Form 860, except FOR from LPSC 3-14 tab "MISO PRA".
Sterlington is composed of [redacted] around 2000.

Q: Did NRG construct the plants in this portfolio?

A: NRG bought most of the capacity from other parties. The complex history of NRG's assembly of the portfolio resulted in complex ownership (and hence the sources of data for my analysis).

NRG acquired the Big Cajun 1 steam units and its shares of the Big Cajun 2 units from the Cajun Electric Power Cooperative in March 2000, following the 1994 bankruptcy of that generation and transmission cooperative, driven by the cost overruns of the River Bend nuclear power plant. Those units are owned and operated by NRG's subsidiary Louisiana Generating.

NRG acquired and completed the partially-built Sterlington plant in August 2000 and built the rest of the plant. NRG purchased Cottonwood from Kelson Limited Partnership in November 2010.[16] The Big Cajun 1 peakers and Bayou Cove are the only plants in the transaction developed by NRG. These four plants are (according to the EIA Form 860 reports) owned by NRG Sterlington Power, Cottonwood Energy Company, Big Cajun 1 Peaking Power and Bayou Cove Peaking Power, respectively.

[16] The Sterlington units are very inefficient and [redacted]. Its forced outage rate has been about [redacted]%, compared to [redacted] [redacted]% for Bayou Cove and the Big Cajun peakers. [redacted] *See* Response to LPSC 1-8 at pp. 4-1 and 4-16.

2. The Wholesale Contracts

Q: Which wholesale contracts would be included in the transaction?

A: Table 2 lists the long-term contracts that NRG would transfer to Cleco Cajun, the peak demand and energy associated with each contract, the annual sales of the buyer, and the price paid by the buyer in 2017.[17] I also indicate in bold the six cooperatives who must give five-year notice of termination, by some time in 2020, to prevent the contracts continuing on an annual basis past 2025.

[17] In Response to LPSC 8-12, Cleco provides the expiration dates marked as HSPM, even though NRG publicly reports the expiration dates to FERC. However, a number of the dates Cleco provided in Response to LPSC 8-12 (all cooperative expirations except for [redacted] and [redacted]) differ somewhat from those that NRG reported to FERC. A spot check indicates that the dates in Response to LPSC 8-12 are consistent with the contracts, and that all the coop contracts end by [redacted]/2025 . It is not clear why NRG has been reporting different dates to FERC.

Table 2: NRG Sales Contracts to be Transferred to Cleco Cajun

Buyer	Type	Reported Expiration Date	MW 2017	Sales 2016 (GWh)	Purchases 2017 (GWh)	Energy Price 2017 $/MWh
Beauregard Electric Cooperative	Coop	**12/31/2025**		1,037	1,078	$59.60
Claiborne Electric Cooperative	Coop	3/31/2025		625	624	$55.25
Concordia Electric Cooperative	Coop	**12/31/2025**		206	195	$62.40
Jefferson Davis Electric Cooperative	Coop	**12/31/2025**		255	261	$59.19
Northeast Louisiana Power Cooperative	Coop	12/31/2025		245	252	$65.30
Pointe Coupee EMC	Coop	**12/31/2025**		221	220	$59.28
South Louisiana Electric Coop Assoc	Coop	**12/31/2025**		554	552	$58.66
Southwest Louisiana EMC	Coop	**12/31/2025**		2,355	2,383	$61.49
Washington-St. Tammany Electric Corp	Coop	3/31/2025		982	1,006	$60.15
City of Caldwell, Texas	Muni	5/31/2019	13.4		60	$52.89
City of Kirbyville, Texas	Muni	5/31/2019	4.6		18	$55.13
City of New Roads, Louisiana	Muni	5/31/2021	11.2		22	$53.87
City of Newton, Texas	Muni	5/31/2019	5		48	$40.95
City of West Memphis, Arkansas	Muni	5/31/2021		373	92	$45.85
SWEPCo	IOU	12/31/2026	50			$7/kW-mo

Sources: Louisiana Generating and NRG Power Marketing EQRs for 2017; Electric Sales, Revenue, and Average Price, EIA, Table 10 (2016 Utility Bundled Retail Sales—Total), at https://www.eia.gov/electricity/sales_revenue_price/.
The expiration dates in **bold** indicate that the contract continues on an annual basis unless either party gives five-year notice.

The Sales column reflects the Buyer's total sales to ultimate customers, from EIA, while the Purchases column represents the sales from Louisiana Generating (for the coops and SWEPCo) and NRG Power Marketing (for the munis) to the Buyer. Other than the difference in time period, the sales and purchase values will differ because the coops have other supply sources

(Southwest Power Administration hydro, internal qualifying facilities) and the purchases include losses and utility energy use.[18]

The muni prices per MWh in Table 2 include charges of $5/kW-month for the Texas munis, whose contracts were signed in April 2014, and $0.49/kW-month for New Roads, which signed its current contract in January 2016. The price for requirements service paid by the coops reflects market conditions in 2000 or 2002, while the much lower price for similar service paid by West Memphis reflects the much lower market prices expected by 2016.

Louisiana Generating holds the contracts with the cooperatives and SWEPCo (whose contract appears to be a legacy from a cooperative that SWEPCo purchased prior to NRG's assumption of the contracts), while NRG Power Marketing has the municipal utility contracts.

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[18] The available data differ among the contracts. The sellers do not report billing demand for the requirement contracts (with the coops and West Memphis), and most of the munis do not appear in the EIA sales data. https://www.eia.gov/electricity/sales_revenue_price/. Four of the five municipal utilities do not appear in that database.

3. Cottonwood

Q: What is Cleco's plan for the Cottonwood plant?

A: The Cottonwood combined-cycle plant, located in East Texas, is the portion of the NRG resources being transferred to Cleco Cajun that is most likely to be economic in the MISO market. Unlike the Louisiana plants, Cleco does not intend to operate this plant itself, at least through 2025. Instead, Cleco would lease the plant back to NRG for [redacted] 2025.[19] Cleco has not provided any forecast of the Cottonwood's market revenues, during or after the lease, which makes any determination of its value speculative.

Q: What does Cleco plan to do with Cottonwood after the lease expires?

A: That is unclear. Cleco assumes that it will be able to [redacted] in 2025 (Response to LPSC 3-14), but has offered no evidence to support that assumption.

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[19] If Cottonwood is needed by Cleco Power, Cleco Corp [redacted].

4. Uncertainties Related to the Transaction

Q: What are the major uncertainties related to the transaction?

A: All forecasts involve uncertainty and risk.[20] The particular risks that Cleco faces in this transaction include:

- Most of the NRG resources that Cleco Cajun would own and operate (and which Cleco proposes to transfer to Cleco Power in the future) lose money in the competitive market. Even with Cleco's own undocumented assumptions regarding costs and revenues, [redacted] resources that Cleco analyzes ([redacted]) are not worth running.[21] Any further deterioration in market prices or increase in plant costs would increase those losses.

- To the extent that market energy prices change due to changes in gas price, the fuel costs of the gas-fired units will change along with them,

[20] Technically speaking, risk is the distribution of outcomes within a known probability distribution, while uncertainty refers to a more fundamental lack of knowledge concerning the underlying probabilities. In popular terminology, uncertainty often describes minor variability, while risk refers to major danger. I will generally use the popular meanings of these terms.

[21] In discovery, Cleco provides revenue and cost assumptions it used in these computations, but it is not clear whether even Cleco believes them. When asked for Cleco's own unit-specific projections of fuel, O&M, and capital costs and energy and capacity revenues after 2025, the Company asserted that the requested information was "speculative," "does not exist," and would require Cleco to "create information that does not currently exist.." Response to SC 1.24.

mitigating any change in the value of those resources. Decline in gas prices would make the coal-fired units even more unprofitable.

- The value that Cleco assumes for Cottonwood after 2025 is undocumented. Any reduction in that value would erode Cleco Corp's equity position.

- Cleco assumes that its sales to the coops will increase over time, even though those sales have generally been falling. Continuation of historical trends would result in lower revenues to Cleco.

- The cooperatives are unlikely to extend the existing contracts at the high prices assumed by Cleco. Reductions in those prices are likely to substantially reduce the value of the transaction to Cleco.

5. Cleco Power Resources

Q: What are Cleco Power's generation resources?

A: Table 3 provides the technology, fuel, commercial operation date ("COD"), summer capacity, Cleco Power's ownership share, and Cleco's capacity.

Table 3: Cleco Power's Generation Resources

Plant	Unit	Type	Fuel	COD	Summer MW	Cleco %	Cleco MW
Dolet Hills		ST	Coal	1986	642	50%	321
Nesbitt	1	ST	Gas	1975	421	100%	421
Rodemacher	2	ST	Coal	1982	493	30%	148
Madison	3	ST	Coal	2010	630	100%	630
Teche	3	ST	Gas	1971	333	100%	333
Teche	4	CT	Gas	2011	35	100%	35
Arcadia	1	CC	Gas	2002	556	100%	556
Coughlin	6	CC	Gas	2000	246	100%	246
Coughlin	7	CC	Gas	2000	481	100%	481

The heat recovery steam generator portions of Coughlin 6 and 7 were installed in 1961 and 1966, respectively.

Nesbitt, Rodemacher, and Madison are all located at a location that Cleco Power calls Brame Energy Center, so the units are sometimes called Brame 1, 2, and 3, respectively.[22]

B. Potential Effect of Transaction on Cleco Power Customers

Q: How would the proposed transaction affect Cleco ratepayers?

A: As discussed below, the effects differ between the two phases of the proposed transaction. In Phase I, the effects on ratepayers are primarily due to the consequences of the transaction for Cleco Corp. Cleco Corp is the only source of equity for Cleco Power, so anything that harms the financial status of Cleco Corp endangers Cleco Power customers. The ability of Cleco Cajun to repay the purchase price and earn a return for Cleco Corp affects the financial health of Cleco Corp, which would affect the ability of Cleco Power to make investments necessary for reliable power supply at the lowest possible cost.

In Phase II, the potential costs to ratepayers are more direct. Transferring the generation assets to Cleco Power would produce MISO revenues lower than their costs and would thus increase revenue requirements imposed on ratepayers.

The two phases are separable conceptually, but not practically. Cleco Corp's determination that the transaction would be profitable for its owners assumes the [redacted],[23] while Cleco's presentation to the rating agencies indicates that the transfer [redacted].[24]

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[22] Sometimes Cleco mixes its terminology, referring to "Rodemacher," for example.

[23] Response to LPSC 3-14, tab PRA.

[24] Response to LPSC 1-15, Attachment B at 4.

Any uneconomic generation transferred to Cleco Power (either by transferring ownership or through a power-purchase arrangement) would increase the rates and bills of its retail customers. Depending on a number of future conditions, uneconomic generation may also affect the rates paid by the Louisiana jurisdictional cooperatives and their customers.

Q: When is Cleco Corp expecting to transfer the generation from Cleco Cajun to Cleco Power?

A: Cleco is not consistent about its plans. On the one hand, in April 2018, Cleco told the rating agencies that it "[redacted]."[25]

On the other hand, Response to LPSC 3-14 assumes that the generation will all be owned by Cleco Cajun through about [redacted], with generation transferred to Cleco Power around [redacted]. This appears to be an earlier projection than the rating-agency presentation in Response to LPSC 1-15, Attachment B.[26]

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[25] *Id.*

[26] This point raises on a continuing problem in reviewing Cleco's responses. Cleco provides obsolete documents without updating them or indicating which document provides Cleco's current position.

Q: What resources does Cleco Corp assume it will transfer to Cleco Power?

A: It appears from Response to LPSC 3-14 that Cleco Corp is planning on transferring all of the remaining generation except for [redacted], following the retirement of [redacted] and [redacted]. According to Response to LPSC 1-15, Attachment B, all of the [redacted] would be transferred to Cleco Power.[27]

Q: Which units does Cleco Corp plan to retire and does it plan to retire those before or after transferring the generation to Cleco Power?

A: That is unclear given the uncertainty around when Cleco Corp intends to transfer the units to Cleco Power. Response to LPSC 3-14 shows [redacted] retiring either [redacted] (in the MISO PRA tab) or around [redacted] (in the Base Gas and Expenses & Capex tabs), which would be around the transfer date assumed in the Response to LPSC 3-14 and after the transfer date in the rating agency presentation. The Response to LPSC 3-14 shows [redacted] retiring about [redacted] in the MISO PRA tab or around [redacted] in the Expenses & Capex tab.

[27] It is not clear which environmental liabilities (such as coal ash disposal sites) Cleco Corp expects to transfer to Cleco Power.

Q: What does Cleco expect that it will do with Cottonwood?

A: Cleco has declined to say. Cleco does not provide any projection for the revenues from Cottonwood, other than the lease payment of $[redacted] million annually through May 2025, and a "terminal value" of $[redacted] million in 2025.[28] It is not clear what Cleco Corp intends to do with this plant, but the terminal value may be a sales price, the present value of a future lease, or some other valuation.[29]

Q: What are the risks and uncertainties in the transaction?

A: All forecasts are uncertain, but some are riskier than others.[30] In the case of the proposed transaction, the net benefit (if any) of operating the Cleco Cajun units would face a number of market and operating risks, both related to the value of the generators and the value of the cooperative contracts.[31]

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[28] The lease payment is shown as "CW Toll Revenue" in Response to LPSC 3-14 Attachment A, Summary tab; the terminal value is shown in the same tab.

[29] Cleco has not provided any derivation of this value. On a discovery call with Sierra Club on July 31, Cleco said that the terminal value was determined from a $/kW value, which suggests that it is a sales price.

[30] This is true even of well-documented and well-reasoned forecasts, let alone Cleco's undocumented assumptions.

[31] Cleco does not assume any above-market value from extension of the muni or SWEPCo contracts.

It is important to recall that Cleco Power is completely reliant on Cleco Corp for equity, so any risks of the $1 billion acquisition can affect Cleco Power. The owners of Cleco Corp have concluded that this transaction would be beneficial to them. It is far from clear that the transactions would have any benefits to ratepayers.

Q: What risks would Cleco Cajun and/or Cleco Power face related to the value of the power plants it proposes to acquire from NRG?

A: Cleco assumes that most of the Cleco Cajun resources would generate some profit in the MISO energy market to at least partially offset their fixed costs.[32] While I conclude that most of the NRG resources that Cleco intends to operate are uneconomic to continue operating, even at the market energy prices assumed by Cleco, those prices could be lower and the losses even higher.

The market energy prices are affected by conditions in MISO South (Louisiana, Texas, Mississippi, and Arkansas) and neighboring regions, including the energy load levels, the amount of new renewables and high-efficiency gas capacity, and the price of natural gas. The gas price is more an issue for coal plants than gas plants, since falling gas prices will reduce both

[32] The exception is [redacted], which Cleco expects to be cost more in fuel and variable O&M than it earns in energy revenue, as I describe in Section III.B.

the market price of energy and the cost of fuel for the gas plants, but will not have any comparable benefit for the coal plants.

Market capacity prices are similarly affected by load growth, additions, and retirements in MISO South, the rest of MISO, and adjacent areas. Lower market energy prices would mean even larger losses from operation of the Cleco Cajun units.

Almost all the costs of running the Cleco Cajun plants are subject to changes in market prices (for fuel, chemicals and maintenance services), inflation (in operating labor and equipment), future environmental requirements (for air quality, carbon emissions, water quality, and waste handling) and plant condition (affecting operating costs, maintenance, capital expenditures, availability, heat rate and fuel cost per kWh).[33] Future plant condition is particularly risky for the Big Cajun steam units, which will soon all be over 40 years old.

Q: What risks would Cleco face related to the value of the contracts it proposes to acquire from NRG?

A: Cleco Cajun (and later Cleco Power) would face serious risks of receiving lower revenues than Cleco projects, due to at least two factors. First, load

[33] Reduced availability would reduce both energy revenues and unforced capacity, which determines capacity revenues.

growth of the cooperative contract customers (offset by other resources) affects contract revenues through the life of the sales contracts. Cleco projects [redacted] annual growth in sales to those customers (or about [redacted]% cumulative by 2025 and [redacted]% by 2036).[34] Cleco has offered no evidence to support that assumption, which is inconsistent with the historical record. The Louisiana Generating EQRs show that actual sales to the nine cooperatives have fallen by an average of –0.7% annually from 2010 to 2017. Only two of the cooperatives bought more energy in 2017 than 2010; even for these two cooperatives, sales rose less than 0.5% annually. If the sales trend of the last five years continues, Cleco's forecast of sales and base revenues would be overstated by about 10% (roughly $[redacted] million) by 2025, 25% (about $[redacted] million) by 2036 and about $[redacted] million overall.

Second, post-2025 revenues from the contracts are highly sensitive to whether the cooperatives renew their contracts, and the prices at which they renew. Cleco assumes that all the cooperatives will renew, sales will continue to grow, and that the renewed prices will still be well above market prices.

[34] Response to LPSC 3-14, Attachment A.

Q: What prices does Cleco assume the coops would pay after their contracts are renewed?

A: The cooperatives paid NRG an average of $60/MWh in 2017, when the hour-weighted energy price was about $30/MWh. The cost of serving the coops from the market would have been somewhat higher, to cover small capacity and ancillary charges and to reflect the fact that customers tend to use more energy at high-priced hours. In 2019–2024, Cleco forecasts that its revenues from the cooperatives would be about [redacted]% of its forecast of the market costs of energy and capacity to serve the contracts.[35] Cleco assumes that the average price of the renewed contracts in 2026 would be just [redacted]% lower than the price of the legacy contracts in 2024.[36] After the assumed contract renewals, from 2026 to 2034, Cleco projects that the cooperatives would pay about [redacted]% of the cost of energy and capacity. In the last two years of Cleco's forecast, its assumed ratio of contract price to market cost falls below [redacted]%.

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[35] The net effect of MISO ancillary and administrative charges and credits is only about 1% of the energy cost. *See* https://docs.misoenergy.org/marketreports/20180820_sr_ctsl.pdf.

[36] Response to LPSC 3-14, Attachment A, Summary tab.

Q: Are the cooperatives likely to agree to extension of the contracts at such high prices?

A: I doubt it. Cleco offers no evidence that it could secure long-term contracts at these high mark-ups. In my experience with power procurement in competitive markets, winning bids are usually within 10% of projected market prices.

Q: What has been NRG's success rate for getting utilities to renew their expiring long-term contracts with Louisiana Generating?

A: When Louisiana Generating acquired the Big Cajun plants and assumed (or signed new) wholesale contracts with Cajun Electric Coop's customers, it wound up with contracts with eleven Louisiana cooperatives, SWEPCo, and three Mississippi agencies.[37] The contracts with four of the cooperatives and all three of the Mississippi agencies had expiration dates between 2009 and 2014. Of these seven customers, two cooperatives (Claiborne and Washington-St. Tammany) renewed, while the other two cooperatives (Dixie EMC and Valley EMC) and the three Mississippi agencies did not.[38] That renewal rate (29%) is much lower than the 100% renewal rate that Cleco assumes for 2025.

[37] Municipal Energy Agency of Mississippi, Mississippi Delta Energy Agency and the cooperatives' South Mississippi Electric Power Association.

Q: Considering the information you have provided on pricing and renewal rates, what is a reasonable treatment of future sales to the cooperatives?

A: The cooperatives and municipal utilities are unlikely to renew their contracts at the current prices, considering that other suppliers (e.g., Entergy, AEP, Southern Company, or wholesale marketers) can compete with Cleco Cajun (or Cleco Power) to supply these customers on a bundled requirements basis, and the customers can build or purchase resources or contract for blocks of power and pay MISO for any additional or ancillary services they may need. If Cleco serves new contracts at fixed prices, it will take on additional risks and/or the costs of hedges.

Assuming any profit from wholesale contracts after the 2025 expiration of the cooperative contracts is speculative.

Q: Are there ways to reduce some of the risks of the transaction, if the Commission were to approve it?

A: Yes. Cleco told the rating agencies in November 2017 that the acquisition of the NRG assets provides “[redacted].”[39] I have not seen any effort by Cleco to identify those opportunities, but retiring the uneconomic Big Cajun 2 Units 1 and 3,

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[38] It does not appear that NRG was able to replace these contracts with similarly priced contracts with other wholesale customers.

[39] Response to LPSC 1-15, Attachment A at 7.

using some of the acquired gas-fired capacity to replace Cleco's uneconomic Dolet Hills and Rodemacher units, and serving the cooperative load from market purchases would significantly reduce and offset the risk to Cleco Power customers from the transaction.

III. The Economics of the NRG Resources

Q: What information do you provide in this section?

A: I start by describing the economics of the NRG assets as shown in Cleco's own discovery responses. Even under Cleco Corp's own unsupported assumptions, most of the generation units it has proposed to purchase are unprofitable. I then support those conclusions by assembling publicly-available data for the plants' performance, costs and revenues; my independent review of those data is consistent with the conclusion that the coal-fired generating units are significantly uneconomic.

A. Cleco's Results for NRG Unit Economics

Q: Has Cleco provided projections of the costs and benefits of the transaction generation assets?

A: To some degree. Although Cleco provided assumptions of the annual revenues and costs for each of NRG's plants, with the Big Cajun 2 units reported individually,[40] most expenses and capital expenditures are entirely undocumented and unsourced. Because the Applicants refused to provide the bases or source for much of that data, it was difficult to test the reasonableness of those assumptions. All of Cottonwood's costs and revenues are excluded from Cleco's analysis and assumptions, other than the lease payment from NRG to Cleco.[41]

Based on the limited data Cleco did provide, I evaluated six forecast resource groups: two coal-fired (Big Cajun 2 Unit 1 and NRG's share of Big Cajun 2 Unit 3), and four gas-fired plants (the steam Big Cajun 2 Unit 2, the two steam units and two combustion turbines at Big Cajun 1, the four Sterlington combustion-turbine units and the four Bayou Cove units). The discovery response provides the following data for each unit or plant:[42]

- Unit Generation in MWh
- Variable O&M Costs
- Unit Energy Revenue
- Fuel Cost

[40] Response to LPSC 3-14, Attachment A.

[41] Projections of Cottonwood costs are provided in Response to LPSC 8-15, Attachment G.

[42] For Big Cajun 1 and Bayou Cove, Cleco provides the first four items by unit, and the rest for the plant.

- Fixed Expenses
- Payroll
- Insurance
- Property Tax
- Maintenance Operating Expenses
- Maintenance Capital Expenditures
- Environmental Capital Expenditures

The assumed costs do not appear to include any allowance for non-routine repairs or replacements following equipment failure, which would make these cost projections conservative.

Cleco also provides a projection of annual MISO capacity revenue for the NRG fleet. Since Cleco also provided the forced outage rate and MISO-accredited UCAP for each unit, and its forecast of the annual capacity price, I was able to disaggregate the revenue forecast by unit.

Depending on the cost or revenue item, Cleco provides estimates starting in January or July 2018. All the projections run through 2036, unless the resource retires sooner.

Q: Has Cleco provided the derivation of its assumptions?

A: Not in most cases.

Q: What were the results of Cleco's projections for the economics of the NRG units?

A: Table 4 summarizes the profitability of each of the six reported plants or units. I aggregated the relevant cost and revenue items for each resource; Cleco does not report the total in this manner. These analyses do not include any costs of financing the procurement, the common costs of managing the plants, transmission costs, or any other costs of servicing the wholesale power contracts.

Table 4: Cleco Projection of NRG Resource Profitability

		Years		Cumulative Profit	
	Retire	Profitable	Total	2019-2036	2019-2025
Bayou Cove	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sterlington	[redacted]	[redacted]	[redacted]		[redacted]
Big Cajun 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Big Cajun 2 U1	[redacted]	[redacted]	[redacted]		[redacted]
Big Cajun 2 U2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Big Cajun 2 U3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Note that Cleco projects the retirement of [redacted] resources within the analysis period. Figure 1 and Table 5 show Cleco's forecast of annual profit by plant or unit, including the last half of 2018. These profits (or more often losses) do not include any costs of the transaction, any return, or any of the overhead costs that Cleco identifies at the Cleco Cajun level.

[redacted]

Table 5: Cleco Projection of NRG Resources Annual Profitability ($M)

	Bayou Cove	Sterlington	Big Cajun 1	Big Cajun 2 Unit 1	Big Cajun 2 Unit 2	Big Cajun 2 Unit 3
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[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]	
2034	[redacted]		[redacted]		[redacted]	
2035	[redacted]		[redacted]		[redacted]	
2036	[redacted]		[redacted]		[redacted]	
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

a. Big Cajun 2 Unit 1 is modeled as retiring in April 2025, so its losses are lower in that year.

Q: Please summarize these projections.

A: With Cleco's assumed costs and market revenues, the coal-fired Big Cajun 2 Units 1 and 3 are [redacted]. The gas-fired plants [redacted] in most years, but [redacted]. Only [redacted] [redacted] in either the short or long term.

Q: What are the implications of these Cleco forecasts?

A: Neither Cleco nor any other party should be acquiring and running Big Cajun 2 Units 1 or 3. These units are [redacted], even given Cleco's assumptions. There is no clear reason to acquire any of the other units, except for [redacted].

Q: Considering the abysmal economics of these resources, which units is Cleco proposing to retire immediately upon gaining control of the assets?

A: Cleco claims to have "no near term plans to retire any generating units. Big Cajun 2 Unit 1 has an environmental consent decree that requires action which may require fuel conversion, environmental mitigation, or retirement by 2025."[43] By 2025, Cleco projects that Cajun 2 Unit 1 would lose [redacted] dollars. On its face, Cleco's lack of planning to retire the money-losing resources, especially Big Cajun 2 Unit 1, makes no economic sense, unless Cleco Corp has some plans for extracting hidden value from the money-losing resources, such as getting the cooperatives or Cleco Power's

[43] Response to LPSC 1-29

customers to subsidize them. Such a solution for Cleco Corp's owners would be a massive loss for Louisiana electric consumers.

B. Confirming Data and Analyses

Q: Were you able to check the Cleco assumptions about the costs and revenues of the NRG resources against any actual data or independent estimates?

A: Yes, to some extent, using data from EIA (Forms 860 and 923), FERC (the Electric Quarterly Report or EQR) and the EPA (e.g., the Air Markets Program Database). Table 6 provides some data on the two coal units.

Table 6: Big Cajun 2 Coal Unit Operating Characteristics

Unit	Year Installed	Summer Capacity (MW)	Ownership Share	MW	Co-Owners	2017 Capacity Factor	2017 Heat Rate (Btu/kWh)	Turndown Ratio
1	1981	568	100%	568		40%	11,445	26%
3	1983	580	58%	336	Entergy LA, Energy TX	64%	10,669	31%

Data sources:

2017ER EIA 860, Generator and Owners files, https://www.eia.gov/electricity/data/eia860/
2017ER EIA 923, https://www.eia.gov/electricity/data/eia923/

Neither of the Big Cajun 2 coal units is efficient. Unit 1 has a particularly high heat rate and (for a coal plant) a low capacity factor. The units can only operate down to about 30% of their rated capacity; when prices fall (e.g., over night or on weekends), the units must either run at a loss to stay warm, or shut down and go through the long restart and ramp-up process the next time energy prices are high enough to make them economic to run.

2. Fuel and O&M

Q: What information do you have on the historical fuel and O&M costs of the Big Cajun 2 coal units?

A: Table 7 summarizes the Big Cajun 2 fixed and variable O&M data that Cleco provided in response to items 4(e) and 4(f) of Sierra Club's subpoena to NRG,[44] and the fuel and total nonfuel O&M costs for Big Cajun 2, unit 3, in dollars per megawatt-hour, from the Entergy Texas FERC Form 1 reports for those years.[45]

44 *See* Supplemental Response to SC 1.9 and 1.23. As reflected in the table below, Cleco refused to provide, and apparently did not have or review, NRG's historical fuel costs for operating the Big Cajun 2 units. When asked to provide historical fuel and O&M data, Cleco responded that it did not possess the data. Response to SC 1.9, 1.21, 1.23 through 1.26, 1.28, and 1.30 (all asserting that Cleco is "not in possession" of the requested data).

45 Ex. PLC-3, Entergy Texas, FERC Form 1, pp. 402-03.

Table 7: Big Cajun 2 Coal Fuel and Non-Fuel O&M Costs ($/MWh)

	Big Cajun 2 Unit 1			Big Cajun 2 Unit 2			Big Cajun 2 Unit 3			
	From Subpoena			From Subpoena			From Subpoena			From FERC 1
	Variable	Fixed	Total	Variable	Fixed	Total	Variable	Fixed	Total	
Non-Fuel O&M										
2014										$5.24
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$13.75
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$8.59
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$7.58
Fuel										
2014										$24.65
2015										$25.78
2016										$25.98
2017										$24.74
Total										
2014										$29.89
2015										$39.53
2016										$34.58
2017										$5.24

Q: Have you found generic estimates of O&M costs for coal plants comparable to these units?

A: Yes. The U.S. EPA estimated variable and fixed O&M for coal plants in a May 2018 report.[46] The variable O&M cost estimates are differentiated based on the sulfur dioxide (SO_2), nitrogen oxides (NOx) and mercury control. Big Cajun 2, Unit 1 has dry sorbent injection for sulfur control, and both units have activated carbon injection for mercury control and selective non-catalytic reduction (SNCR) for NOx.[47] The EPA fixed O&M cost estimates are differentiated based on the same pollution controls and unit age (under 40 years, 40 to 50 years, and older).

Table 8 summarizes the results of applying the EPA categories to the coal units and applying 2% annual inflation from the 2016 dollars.

[46] Documentation for EPA Base Case v.6 Using the Integrated Planning Model, EPA, May 2018, Tables 4-8 and 4-9. *See* www.epa.gov/sites/production/files/2018-05/documents/epa_platform_v6_documentation_-_chapter_4.pdf, attached as Ex. PLC-8.

[47] 2017 Form EIA-860 Data - Schedule 6B, “Emission Standards and Control Strategies,” https://www.eia.gov/electricity/data/eia860/.

Table 8: EPA Non-Fuel O&M Estimates for Big Cajun 2 Coal Units (2016$)

Unit	Year Installed	Variable O&M $/MWh	Age at 1/2019	Fixed O&M $/kW-yr 2019	Fixed O&M $/MWh @ 50% capacity factor
1	1981	$6.14	37	$30	$7.8
3	1983	$5.17	35	$29	$7.3

3. Capital Expenditures

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

A: I have compiled the historical additions to capital plant in service for Big Cajun 2, Unit 3, from the Entergy Louisiana and Entergy Texas FERC Form 1 reports, for 2012–2017.[48]

Q: What have been the historical capital additions for the Big Cajun 2 coal units?

A: Table 9 lists the net annual capital additions by plant, computed from the change in capital cost reported in the annual FERC Form 1 reports.[49] These values represent the capital additions at the plant in the particular year, minus the retirements of equipment at that plant. The interim accounting retirements

[48] *See* Ex. PLC-3.

do not generally reduce revenue requirements, since an equal amount of accumulated depreciation is removed, leaving net plant in service unchanged, so the net additions understate the costs imposed on ratepayers. Where the capital cost declined from year to year, I left the cell blank. I convert those capital additions to $/kW by dividing by the reporting utilities' ownership share of the unit, and to dollars per megawatt-hour, as well as the average capital additions over the last five years. Since these values are net of retirements, they understate the actual costs to ratepayers.

Table 9: Big Cajun 2 Unit 3 Net Capital Additions

	% of Unit	2013	2014	2015	2016	2017	Average
$ million	42%	$0.65	$10.99	$3.41	$6.74	$0.32	
$/kW-year		$2.6	$44.5	$13.9	$27.4	$1.3	$17.9
$/MWh		$0.5	$6.7	$3.2	$5.4	$0.2	$3.2

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

Q: Did Cleco provide any data on the historical capital additions for the NRG resources?

A: Only belatedly. On August 14, 2018, Cleco provided historical data and NRG's forecasts for "major maintenance capital expenditures" at its resources, in Attachments A–F of Response to LPSC 8-15. This cost category does not include environmental capital additions, and may exclude other types of expenditures. The data are summarized in Table 10.

Table 10: Major Maintenance Capital Expenditures for the NRG Resources

	2013	2014	2015	2016	2017	2018	2019	2020	2021
$ million									
Bayou Cove	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BC1 Steam	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BC1 Peaking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Big Cajun 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sterlington	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cottonwood	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
$/kW-year									
Bayou Cove	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BC1 Steam	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BC1 Peaking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Big Cajun 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sterlington	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cottonwood	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Unfortunately, Cleco did not differentiate all of the Big Cajun 2 capital additions among the three very different units, but NRG forecasts much higher total capital expenditures for Big Cajun 2 for 2018–2021 than Cleco assumes in Response to LPSC 3-14, Attachment A, by about $[redacted] million.

Q: Have you found any generic projections of coal-plant capital additions to supplement the data you found for the Big Cajun 2 coal units?

A: Yes. In preparing the 2018 Annual Energy Outlook, which included an economic analysis of continued plant operation, EIA estimated the average annual capital additions for coal plants, among other technologies:

> The average annual capital additions for existing plants are…$18 per kW for coal plants…(in 2017 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age, an additional $7 per kW capital charge for fossil plants…to reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging.[50]

This analysis suggests that the two coal units would have capital additions of $25/kW-year, which is [redacted] Cleco's projections.

Q: How does this information affect your opinion regarding the Cleco's assumed capital additions for the NRG resources?

A: Cleco's assumptions appear to be optimistic and understated. As a result, the NRG resources are likely to be even larger burdens on Cleco and its

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[50] Assumptions to the Annual Energy Outlook 2018, EIA, April 2018, Electricity Market Module at p. 13, https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

ratepayers that I computed in Section III.A, which relied on Cleco's assumptions.

4. Historical Market Prices

a) MISO Energy Prices

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

A: Table 11 provides summary price statistics for the market price (the day-ahead locational marginal price ("LMP")) at the Louisiana Generating hub in 2016 and 2017, as reported by MISO.

Table 11: Hourly Energy Prices ($/MWh)

	2016	**2017**
Mean	$26.6	$30.3
Minimum	-$25.9	$1.6
25th Percentile	$19.7	$22.3
50th Percentile	$22.7	$25.6
75th Percentile	$28.5	$30.8
Maximum	$426.6	$644.5

Table 12 provides the average price for each coal unit and for some gas-fired units and plants for which the data were readily available. I weighted the market energy price in each hour by the unit gross hourly output reported in the EPA Air Markets Program Data ("AMPD") web site, to compute the average price received by the plant as it operated.[51]

Table 12: Market Energy Prices Weighted by Gross Output

	Average Value of Energy Generated ($/MWh)		Gross Capacity Factor	
	2016	**2017**	**2016**	**2017**
Bayou Cove	$49.29	$69.54	4.5%	2.2%
Big Cajun 1 Steam	$39.26	$42.55	1.7%	3.1%
Big Cajun 1 Peaking	$58.98	$75.62	2.1%	2.2%
Big Cajun 2 Unit 1	$32.88	$33.41	23%	39%
Big Cajun 2 Unit 2	$26.76	$44.46	45%	11%
Big Cajun 2 Unit 3	$29.19	$30.78	57%	63%

The general pattern in Table 12 is that higher capacity factors are associated with lower average prices. At one extreme, the Bayou Cove and Big Cajun 1 combustion turbines run only when prices are high, and their output has very high average energy values. At the other extreme, Big Cajun 2 Unit 3 runs about 60% of the time, and gets the lowest market prices

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[51] *See* https://ampd.epa.gov/ampd/. The EPA data are for gross output at the generator, before netting out the plant's own power consumption. The data thus overstate the amount of energy for which the NRG would have been paid.

for its energy.[52] The disadvantages faced by slow-responding steam plants is also evident in Table 12. The Big Cajun 1 steam units run less than the Bayou Cove and Big Cajun 1 combustion turbines, but since they are less agile, the steam units are less effective in picking off the high-priced hours, and the steam units get lower energy values than the combustion turbines. When coal units are not profitable to run in all hours, they face the same sort of problem that the Big Cajun 1 steam units do, as they are forced to run in unprofitable hours to be available for profitable hours, while missing out on some profitable hours entirely.

Q: How would the coal plants operate if they could run in only the hours in which they were economic?

A: Table 13 summarizes that analysis. I started by estimating the short-run cost for each unit as the sum of 2017 fuel costs and EPA's forecast of variable O&M from Table 8. I then counted the number of hours in which the market energy price exceeded the short-run cost. 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.[53]

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[52] The energy value of the units also varies with whether they are available to operate at high-priced hours and other details of dispatch.

[53] In this section, I consider whether the units are profitable to run in a particular hour, once the operator has committed to capital additions and fixed O&M. Elsewhere, I

Table 13: 2017 Big Cajun 2 Running Cost and LMP in Profitable Hours

	Unit 1	Unit 3
Fuel + VOM ($/MWh)	$33.0	$28.6
When LMP exceeds Fuel + VOM		
Number of Hours	1,076	2,349
% of hours	12%	27%
Average LMP ($/MWh)	$54.8	$43.4
Energy Margin = LMP – (Fuel + VOM)		
$/MWh	$21.8	$14.8
$/kW-year	$23.5	$34.9

In the last section of Table 13, 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).

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

A: The units generated much more energy than they would have if they ran at full power in every profitable hour, and not in any unprofitable hour, as shown in Table 14.

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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.

Table 14: Comparison of Big Cajun 2 Profitable Hours to Capacity Factors

	Unit 1	Unit 3
Profitable Hours	12%	27%
Capacity Factor	43%	67%
Difference	31%	40%

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, the capacity factor for each unit is reduced by forced and maintenance outages. In addition, the coal units cannot cycle up and down fast enough to run in all the profitable hours without running in unprofitable hours. Table 14 shows that in the vast majority of hours, the units ran but were not profitable, as a result of limitations in ramping and load following. NRG seems to have been keeping the units on line in many unprofitable hours, to be able to operate in the profitable hours.

b) Cycling Ability of the Coal Units

Q: To what extent can the 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. Very little public information is available on these technical parameters, but according to EIA's Form 860, the Big Cajun 2 coal units both require "more than 12 hours" from cold shutdown to full load; many combustion turbines require just 10 minutes to one hour to reach full load.[54] The actual startup times for the coal units are probably much longer than 12 hours; coal plants typically require most of a day, or even several days, to reach full power.

Coal plants also tend to ramp up and down slowly once they are on line, and to have other serious constraints operating patterns. For example, once a unit is running, it must stay in operation for several hours to a day or so; once it is shut down, it cannot come back up for hours or even days.

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 is emerging as utilities and other generators add wind capacity (and increasingly, solar capacity) in MISO and neighboring regions.

c) Capacity Prices

Q: Is excess capacity very valuable in the MISO market?

A: No. Table 15 shows the clearing prices in Zone 9 (which includes almost all of Louisiana, along with parts of East Texas) for each of the Planning Reserve Auctions ("PRAs") that MISO has conducted.[55]

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[54] 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.

Table 15: MISO Zone 9 Capacity Prices

PRA	Per unit of UCAP		$/kWh at capacity factor of		
	$/MW-day	$/kW-year	40%	50%	60%
2014/15	$16.44	$6.00	$1.71	$1.37	$1.14
2015/16	$3.29	$1.20	$0.34	$0.27	$0.23
2016/17	$2.99	$1.09	$0.31	$0.25	$0.21
2017/18	$1.50	$0.55	$0.16	$0.13	$0.10
2018/19	$10.00	$3.65	$1.04	$0.83	$0.69
Average	$6.84	$2.50	$0.71	$0.57	$0.48

Zone 9 has always cleared at the same price as Zones 8 (Arkansas) and 10 (Mississippi); in the last two auctions, it has cleared at the same price as all of MISO and (in 2018/19) all but Zone 1.

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

A: Not at the historical market capacity prices. As shown in Section III.B.4.c), the cost of capacity to replace generation with the range of capacity factors that the coal units are likely to achieve is generally under a dollar per MWh.

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[55] From MISO, "2018/2019 Planning Resource Auction Results" at 8 (Apr. 13, 2018), https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf.

If the coal energy were replaced by lower-cost wind or solar, which has capacity value, the cost of supplementary capacity purchases would be even lower.

Q: What are your conclusions about whether the publicly available data supports your conclusions about the economics of the plants proposed for purchase?

A: Using data from EIA (Forms 860 and 923), FERC, and EPA, I was able to check the Cleco assumptions about the costs and revenues of the NRG resources. This publicly-available data supports my conclusion that the NRG coal-fired generating units are significantly uneconomic.

C. Summary

Q: Please summarize your assessment of the NRG generation resources.

A: Even if all goes as Cleco projects, the coal units are big losers economically, the [redacted] are more modest losers,[56] [redacted] almost breaks even, and only Bayou Cove is clearly profitable to continue operating. Considering its age and technology, Cottonwood is also probably profitable to operate, although Cleco has not

[56] Cleco did not break out the costs and revenue of the Big Cajun 1 units. It is possible that the two steam plants are as uneconomic as Big Cajun 2 Unit 2, or worse, but that the combustion turbines are profitable.

provided any historical or projected data on that plant's costs or market revenues.

Taking on the Big Cajun 2 coal plants and running them will just cost Cleco Corp money: by its own projections, Cleco Corp would lose $[redacted] million operating Big Cajun 2 Units 1 and 3 in 2019–2025. That's enough to pay off the $[redacted] million in debt on the NRG acquisition that Cleco expects to have outstanding at June 2025, and provide $[redacted] million in equity.[57] Alternatively, Cleco could shut down the units and continue paying property taxes and employee salaries, and still save approximately $[redacted] compared to running the units.

The economics of this generation fleet present real risks to Cleco Power. Cleco Power is completely reliant on its parent company, Cleco Corp, for any equity infusions required to provide safe, reliable, and least-cost service to its ratepayers. If Cleco Corp over-extends its financial position, Cleco Power could be directly impacted by losing access to equity, having to pay a higher premium for debt, and/or (if Cleco Corp became insolvent) enduring a prolonged period of financial and operational uncertainty and coming under new ownership. Operation of this largely uneconomic

[57] Cleco would probably incur some costs associated with retiring the units, but even so, retirement would leave Cleco Corp closer to its pre-acquisition financial status.

generation fleet would increase the likelihood that Cleco Corp will over-extend or over leverage its financial position.

Any future plan to resolve Cleco Corp's risks by transferring the Big Cajun units (including the gas units) or Sterlington to Cleco Power will make Cleco Power's ratepayers worse off, even if Cleco Corp transfers them for $1. The same is true if Cleco Corp sells the capacity and energy for these plants to Cleco Power, even if it sells the power at going-forward costs, ignoring all sunk costs.

Bayou Cove and Cottonwood can probably operate profitably in the MISO market; depending on future conditions, Cleco Power may be able to pay something for these units and still reduce customer costs. Indeed, acquiring these units at reasonable prices may well be advantageous to Cleco Power customers, to the extent that they were used to facilitate the retirement of the uneconomic Cleco Power coal plants.

IV. The Economics of the NRG Wholesale Contracts

Q: How did NRG acquire the contracts that you describe in Section II.A.2?

A: Seven of the cooperative contracts were executed at the time that NRG purchased the Big Cajun plants from the bankrupt Cajun Electric Power

Coop, which was owned by about a dozen distribution cooperatives.[58] The other two coop contracts were executed in June 2002, for the same purpose. The SWEPCo contract is also a legacy from Cajun Electric Power Coop and is still identified as being from the Cajun Electric Coop in SWEPCo's FERC Form 1.[59]

The contracts between NRG Power Marketing and the munis are five-year agreements executed between 2014 and 2016.

Q: How do these contracts relate to the NRG power plants?

A: There is little direct connection between the power plants and the contracts. Louisiana Generation sells all of the energy, capacity and ancillary services from Big Cajun 2 into the MISO markets and buys all the energy, capacity and ancillary services for its wholesale customers from the MISO markets.[60]

The actual costs of the Big Cajun units [redacted] the cooperative contract prices. Specifically, the energy prices for some of the

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[58] Of the thirteen original owners of the Cajun Electric Coop, nine are represented in Table 2, two were purchased by IOUs, and two allowed their contracts with Louisiana Generating to expire.

[59] Ex. PLC-3, SWEPCo FERC Form 1, p. 326.

[60] This is the standard arrangement for utilities in MISO, including Cleco. Utilities may retain some or all of their capacity for self-supply, buying any shortfall or selling any excess to the MISO capacity market.

buyers is tied in part to the [redacted], while all the cooperatives pay for the [redacted].[61]

According to the contract files in Louisiana Generating's Electric Quarterly Report ("EQR") submitted to FERC, the energy price in the SWEPCo is set at "Fuel cost plus VOM [variable O&M] plus 6 mills/kWh", but SWEPCo does not appear to take any energy under the contract. The SWEPCO FERC Form 1 and the EQRs indicate that Louisiana Generating supplies SWEPCo with only capacity through this contract.

Q: Would the wholesale contracts included in the transaction be profitable?

A: Yes. The prices paid by the cooperatives (which are most of the transaction revenues) are far above the cost to NRG (or in the future, perhaps Cleco Cajun or Cleco Power) of buying the energy, capacity and other services to serve those contracts.

Table 16 compares the total wholesale contract revenues to the contract-related costs (Load Expense, Demand Expense, and Other Pass-through Expenses) that Cleco reports in the Response to LPSC 3-14, Attachment A.

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[61] So far as I can determine, the latter item is not tied to continued operation of the resources.

The revenues include all the contracts (cooperative, muni, and SWEPCo), charges for the transmission facilities dedicated to the cooperatives, and charges for other costs that Louisiana Generating passes through to the buyers. The costs include MISO energy and capacity charges, and the pass-through expenses. I start the analysis in 2019, since the transaction would be unlikely to be completed in 2018.

Table 16: Cleco Projections of Contract Revenue and MISO Costs for the Contracts

	$ Millions				$/MWh		
	Revenue	Costs	Profit	% Markup	Revenue	Costs	Profit
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q: Is Cleco likely to receive these contract revenues?

A: No, for two reasons. First, growth (or lack thereof) in the coops' load (offset by other resources serving the coops or their customers) affects contract revenues through the life of the sales contracts. Cleco projects [redacted] annual growth in sales to those customers (or about [redacted]% cumulative by 2025 and [redacted]% by 2036).[62] Cleco has offered no evidence to support that assumption, which is inconsistent with the historical record. The Louisiana Generating EQRs show that actual sales to the nine cooperatives have fallen by an average of –0.7% annually from 2010 to 2017. Only two of the cooperatives bought more energy in 2017 than 2010; even for these two coops, sales rose less than 0.5% annually. If the sales trend of the last five years continues, Cleco's forecast of sales and base revenues would be overstated by about 10% (roughly $[redacted] million) by 2025, 25% (about $[redacted] million) by 2036 and about $[redacted] million overall.

Second, post-2024 revenues from the contracts are highly sensitive to whether the cooperatives renew their contracts, and the prices at which they renew. Cleco assumes that all the cooperatives will renew, sales will continue to grow, and that the renewed prices will still be well above market prices.

Q: What prices does Cleco assume the coops would pay after their contracts are renewed?

A: The cooperatives paid NRG an average of $60/MWh in 2017, when the hour-weighted energy price was about $30/MWh. The cost of serving the coops from the market would have been somewhat higher, to cover small capacity and ancillary charges and to reflect the fact that customers tend to use more

[62] Response to LPSC 3-14, Attachment A.

energy at high-priced hours. From 2019-2024, Cleco forecasts that its revenues from the cooperatives would be about [redacted]% of its forecast of the market costs of energy and capacity to serve the contracts, as shown in Table 16.[63] Cleco assumes that the average price of the renewed contracts in 2026 would be just [redacted]% lower than the price of the legacy contracts in 2024.[64] After the assumed contract renewals, from 2026 to 2034, Cleco projects that the cooperatives would pay about [redacted]% of the cost of energy and capacity. In the last two years of Cleco's forecast, its assumed ratio of contract price to market cost falls below [redacted]%.

Q: Are the cooperatives likely to agree to extension of the contracts at such high prices?

A: I doubt it. Cleco offers no evidence that it could secure long-term contracts at these high mark-ups. In my experience with power procurement in competitive markets, winning bids are usually within 10% of projected market prices.

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[63] The net effect of MISO ancillary and administrative charges and credits is only about 1% of the energy cost.

See https://docs.misoenergy.org/marketreports/20180820_sr_ctsl.pdf.

[64] Response to LPSC 3-14, Attachment A, Summary tab.

Q: What has been NRG's success rate for getting utilities to renew their expiring long-term contracts with Louisiana Generating?

A: When Louisiana Generating acquired the Big Cajun plants and assumed (or signed new) contracts with Cajun Electric Power Coop's customers, it wound up with contracts with eleven Louisiana cooperatives, SWEPCo and three Mississippi agencies.[65] The contracts with four of the cooperatives and all three of the Mississippi agencies had expiration dates between 2009 and 2014. Of these seven customers, two cooperatives (Claiborne and Washington-St. Tammany) renewed, while the other two cooperatives (Dixie EMC and Valley EMC) and the three Mississippi agencies did not. That renewal rate (29%) is much lower than the 100% renewal rate that Cleco assumes for 2025.

Q: Considering the information you have provided on pricing and renewal rates, what is a reasonable treatment of future sales to the coops?

A: The cooperatives and municipal utilities are unlikely to renew their contracts at the current prices, considering that other suppliers (e.g., Entergy, AEP, Southern Company, or wholesale marketers) can compete with Cleco Cajun (or Cleco Power) to supply these customers on a bundled requirements basis, and the customers can build or purchase resources or contract for blocks of

[65] Municipal Energy Agency of Mississippi, Mississippi Delta Energy Agency and the cooperatives' South Mississippi Electric Power Association.

power and pay MISO for any additional or ancillary services they may need. If Cleco serves new contracts at fixed prices, it will take on additional risks and/or the costs of hedges.

Assuming any profit from wholesale contracts after the 2025 expiration of the cooperative contracts is speculative.

Table 17 scales the revenue and costs down, to reflect the historical decline in load, and ends the contracts in 2015.

Table 17: Cleco Projections of Contract Revenue and Cost ($ Millions)

	Revenue	MISO Supply Costs	Profit
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]

Q: Do the contracts offset the costs and risks of the generation resources that Cleco proposes to acquire?

A: No. As shown in Table 17, the revenue from the coop, muni and SWEPCo contracts exceeds the costs of MISO services to serve those contracts by some $[redacted] million, almost enough to cover the acquisition cost. If Cleco Corp were simply buying the wholesale requirement contracts alone for $1 billion, it would be close to a reasonable deal.

Unfortunately, the contracts do not earn the large profit that would be needed to offset the risks of owning and operating the generation resources. The contract prices are mostly fixed or indexed, and do not rise with the costs of operating the generators. The existing contracts would roughly [redacted] the loss on operating the NRG plants, interest expenses, or other costs. The Commission should not rely on any wholesale contract profit after the expiration of the existing contracts.

The uneconomic power plants completely swamp any possible benefit from the cooperative contracts. Even if all goes as Cleco assumes, operation of the power plants would create $[redacted] million in loses. Moreover, the Response to LPSC 3-14 lists about $[redacted] million in additional expenses (such as overheads and interest payments) that are not tied to specific units (and therefore not reflected in Table 4). That means that even if all goes as Cleco anticipates, operation of the NRG resources will cause Cleco to lose approximately $[redacted] million by 2025. While these loses would be offset from the revenue from the Cottonwood lease, these are not nearly enough to offset the losses. Cleco will be down nearly $[redacted] million through 2025. These values are summarized in **Error! Reference source not found.**; note that the losses could be worse if there are any additional costs or operational problems at the plants.

Table 18: Summary of Non-Contract Profits and Losses, Cleco Assumptions ($M)

Cleco-Cajun-run Plants	[redacted]	
Cottonwood Lease	[redacted]	
Generator net		[redacted]
Other Expenses	[redacted]	
G&A and Economic Development	[redacted]	
Interest	[redacted]	
Financing and transaction fees	[redacted]	
Non-contract total		[redacted]

If the Commission were to condition approval of the Application on the retirement of the uneconomic NRG units (which would be most of them), the Application could be modestly beneficial to Cleco Corp without endangering Cleco Power customers. Moreover, as I discuss in detail below, this deal could present some actual benefits to ratepayers if Cottonwood and Bayou Creek replaced Dolet Hills, Rodemacher, and other uneconomic Cleco Power plants.

V. The Economics of Cleco Power's Generation Resources

Q: Why did you decide to look at the economics of Cleco Power generation?

A: I looked at the economics of this fleet for two reasons. First, the Application asserts that the proposed transaction benefits Cleco Power ratepayers by "reflect[ing] the owner group's continuing commitment to invest in the development and optimization of Louisiana's electric infrastructure…."[66] In evaluating the Application, the Commission should consider whether Cleco Power has "optimized" its generation system by shutting down uneconomic resources.

Second, if Cleco has resources that should be retired and replaced, the procurement of some portion of the NRG portfolio (such as Cottonwood and Bayou Cove) might be advantageous to Cleco ratepayers. If the Commission is inclined to approve the transaction with conditions to ensure ratepayer benefits, it needs understand opportunities to improve the Cleco Power supply mix

Q: What performance and cost components of the Cleco coal units have you reviewed?

A: I have compiled performance data on unit capacity factor and heat rate. I have also assembled cost data for fuel, O&M, overheads, and capital additions. Table 19 summarizes the age, size and ownership of each unit.

[66] Application at 6, 22; Direct testimony of Shane Hilton at 12.

Table 19: Cleco Coal Plants

Plant	Unit	Year Installed	Summer Capacity (MW)	Ownership Share		Co-Owners
				Percent	MW	
Dolet Hills	1	1986	642.1	50%	321	NE TX Elec Coop, OK Muni Power, SWEPCo
Rodemacher	Brame 2	1982	492.5	30%	148	Louisiana E&P Auth, Lafayette Utilities
Madison	Brame 3	2010	629.9	100%	630	--

Data sources:

2017 FERC Form 1, p. 402; 2017ER EIA 860, Generator and Owner files; 2017ER EIA 923

Various data are reported in Cleco's FERC Form 1, EIA's databases for the EIA Form 860 and Form 923 reports, and the EPA's APMD information on power plant hourly fuel use, electric energy output and emissions.

A. Performance Measures

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

A: Table 20 shows each coal unit's 2017 capacity factor and 2017 heat rate, and the ratio of minimum stable load to maximum output for which each unit, from the EIA databases.

Table 20: Coal Plant Technical Performance

Plant	2017 Capacity Factor	2017 Heat Rate (Btu/kWh)	Turndown Rate
Dolet Hills	35%	11,638	38%
Rodemacher	41%	11,722	37%
Madison	66%	9,989	64%

Dolet Hills and Rodemacher have high heat rates, and are even less flexible than the Big Cajun 2 coal units. Both of those units have low capacity factors. Madison has a better heat rate, but only a limited ability to reduce output.

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

A: Table 21 depicts annual capacity factors for each of the Cleco units for the last five years, using Cleco capacity from Table 19 and net generation the FERC Form 1 reports.

Table 21: Cleco Coal Capacity Factors by Unit (2013–2017)

	Dolet Hills	Rodemacher	Madison	Total
2013	54%	66%	73%	67%
2014	52%	48%	78%	66%
2015	76%	46%	63%	65%
2016	60%	39%	69%	62%
2017	35%	41%	66%	54%

In 2013, Cleco's fleet wide coal unit capacity factor was 67%; that had dropped to 54% by 2017.

B. Fuel and O&M

Q: What information do you have on the fuel and O&M costs of the Cleco Power coal units?

A: Table 22 provides data on the fuel and total nonfuel O&M costs for each of the Cleco coal units, in dollars per megawatt-hour, from the FERC Form 1 reports for those years.[67]

[67] *See* Ex. PLC-3, Cleco FERC Form 1, pp. 402-03.

Table 22: Fuel and Non-Fuel O&M Costs by Unit ($/MWh)

	Dolet Hills	Rodemacher	Madison
Non-Fuel O&M			
2014	$12.16	$11.33	$5.47
2015	$9.36	$8.04	$7.62
2016	$11.16	$9.24	$6.74
2017	$19.52	$15.77	$4.88
Fuel			
2014	$45.49	$34.76	$26.77
2015	$47.98	$38.65	$25.08
2016	$51.35	$36.34	$25.07
2017	$45.83	$40.38	$27.30
Total			
2014	$57.65	$46.10	$32.24
2015	$57.34	$46.68	$32.70
2016	$62.51	$45.58	$31.80
2017	$65.34	$56.14	$32.19

Q: Have you found generic estimates of O&M costs for coal plants comparable to these units?

A: The U.S. EPA estimated variable and fixed O&M for coal plants in a May 2018 report.[68] The variable O&M cost estimates are differentiated based on the SO_2, NOx and mercury control technologies for the units. As I understand the situation, Dolet Hills has a low-efficiency wet flue-gas desulfurization ("FGD") that removes only 50% of the flue-gas sulfur, Rodemacher has a dry sorbent injection system, and Madison has circulating fluidized bed boilers and dry FGD for SO_2. All three coal units have activated carbon injection for mercury control and SNCR for NOx.[69] The EPA fixed O&M cost estimates are differentiated based on the same pollution controls and unit age (under 40 years, 40 to 50 years, and older).

Table 23 summarizes the results of applying the EPA categories to the coal units.

[68] Documentation for EPA Base Case v.6 Using the Integrated Planning Model, EPA, May 2018, Tables 4-8 and 4-9. www.epa.gov/sites/production/files/2018-05/documents/epa_platform_v6_documentation_-_chapter_4.pdf, attached as Ex. PLC-8.

[69] 2017 Form EIA-860 Data - Schedule 6B, 'Emission Standards and Control Strategies'.

Table 23: EPA Non-Fuel O&M Estimates (2016$)

Plant	Year Installed	Variable O&M $/MWh	Age at 1/2019	Fixed O&M ($/kW-yr) 2019	Increase in	to
Dolet Hills	1986	$6.35	32	$38	2026	$41
Rodemacher	1982	$10.61	36	$30	2022	$34
Madison	2010	$5.90	8	$38		

The EPA estimates do not appear to be designed to cover fluidized-bed boilers, so the estimate for Madison is a greater extrapolation than for the other units.

Q: How do the EPA estimates for O&M compare to the historical data for the Cleco coal units?

A: The 2017 O&M reported for Dolet Hills and Rodemacher were generally similar to the EPA estimates, while Madison's recent-vintage boilers have O&M much lower than the EPA generic estimates.

C. Capital Additions

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

A: I have compiled the historical additions to capital plant in service for the Cleco plants from the Cleco FERC Form 1 reports, for 2012–2017.

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

A: Table 24 lists the net annual capital additions by plant, computed from the change in capital cost reported in the annual FERC Form 1 reports.[70] These values represent the capital additions at the plant in the particular year, minus the retirements of equipment at that plant. The interim accounting retirements do not generally reduce revenue requirements, since an equal amount of accumulated depreciation is removed, leaving net plant in service unchanged, so the net additions understate the costs imposed on ratepayers. Where the capital cost declined from year to year, I left the cell blank.

Table 24: Coal Unit Net Capital Additions ($M)

	% of Unit	2013	2014	2015	2016	2017
Dolet Hills	50%	$6.84	$76.47	$0.56	$3.27	$7.77
Rodemacher	30%	$3.61	$2.71	$44.24	$1.63	$0.69
Madison	100%	$9.78	$7.47	$4.74	$0.86	$13.51

In Table 25, I convert those capital additions to $/kW by dividing by the reporting utility's ownership share of the unit, as well as the average capital additions over the last five years. Since these values are net of retirements, they understate the actual costs to ratepayers.

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

Table 25: Coal Unit Net Capital Additions ($/kW)

	2013	2014	2015	2016	2017	Average	Except Outliers
Dolet Hills	$21.3	$238.2	$1.7	$10.2	$24.2	$59.1	$14.4
Rodemacher	$24.4	$18.3	$298.9	$11.0	$4.7	$71.5	$14.6
Madison	$15.5	$11.9	$7.5	$1.4	$21.4	$11.5	$11.5

Some of these additions (e.g., Rodemacher 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. I therefore also computed the average without those outliers.

Table 26 presents the same data, in dollars per megawatt-hour.

Table 26: Coal Unit Net Capital Additions ($/MWh)

	2013	2014	2015	2016	2017	Average	Except Outliers
Dolet Hills	$4.5	$52.7	$0.3	$1.9	$7.8	$13.5	$3.6
Rodemacher	$4.2	$4.4	$73.5	$3.2	$1.3	$17.3	$3.3
Madison	$2.4	$1.7	$1.4	$0.2	$3.7	$1.9	$1.9

Q: Have you found any generic projections of coal-plant capital additions to supplement the data you found for the Cleco units?

A: Yes. In preparing the 2018 Annual Energy Outlook, which included an economic analysis of continued plant operation, the EIA estimated the average annual capital additions for coal plants, among other technologies:

> The average annual capital additions for existing plants are…$18 per kW for coal plants…(in 2017 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age, an additional $7 per kW capital charge for fossil plants…to reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging.[71]

This analysis suggests that the coal units would have capital additions of $25/kW-year, except for Madison, which would spend $18/kW-year. Those values are consistent with the Cleco-specific data.

[71] Assumptions to the Annual Energy Outlook 2018, EIA, April 2018, Electricity Market Module, page 13: https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

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, such as social security, unemployment taxes, pensions, and benefits (e.g., health and life insurance, education assistance).
- Property insurance.
- Property taxes.
- 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 a jointly-owned plant marks up its O&M charges to the joint owners to include these other costs. As shown in Table 19, Dolet Hills is partially owned by SWEPCo.[72] 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 owners' 2014 to 2017 FERC Form 1 page 402 data for Dolet Hills, the non-fuel O&M per kWh charged to SWEPCo exceeds that reported by Cleco by an average of 19%, as shown in Table 27.

Table 27: Implied Overheads, Dolet Hills Non-Fuel O&M

	$/kWh		
	Cleco	**SWEPCo**	**Markup**
2014	$0.0122	$0.0148	21.5%
2015	$0.0094	$0.0106	12.8%
2016	$0.0112	$0.0141	26.6%
2017	$0.0195	$0.0227	16.1%
Average			19.3%

From these comparisons, it appears that the indirect O&M costs not reflected in the Cleco unit-specific data are on the order of 19% of direct non-fuel O&M.

72 The other owners of Dolet Hills (Northeast Texas Elec Coop and Oklahoma Municipal Power Authority) and Rodemacher (Louisiana Energy & Power Authority and Lafayette Utilities) are publicly-owned utilities, which do not file FERC Form 1 or routinely report these detailed cost data.

Since I do not have any direct data for the overheads on Madison and Rodemacher, I will assume that those overheads are also 19% of non-fuel O&M.[73]

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: Table 28 shows the total costs of keeping each coal unit running, from 2013 to 2017, using the public data that I develop above, including the 19% overhead adder on non-fuel O&M.

[73] The historical data I have on the costs of Big Cajun 2, Unit 3 would include the overheads charged by Louisiana Generating to the Entergy co-owners. The forecast costs that Cleco has provided for the NRG units include at least some of the overhead costs.

Table 28: Costs of Running the Cleco Coal Units ($/MWh)

		2013	2014	2015	2016	2017
Dolet Hills	Fuel	$43.5	$45.5	$48.0	$51.4	$45.8
	O&M	$13.9	$12.2	$9.4	$11.2	$19.5
	Capital Additions	$4.5	**$52.7**	$0.3	$1.9	$7.8
	Overheads	$2.6	$2.3	$1.8	$2.1	$3.7
	Total Cost	$64.4	$112.7	$59.4	$66.6	$76.9
Rodemacher	Fuel	$34.3	$34.8	$38.6	$36.3	$40.4
	O&M	$5.5	$11.3	$8.0	$9.2	$15.8
	Capital Additions	$4.2	$4.4	**$73.5**	$3.2	$1.3
	Overheads	$1.1	$2.2	$1.5	$1.8	$3.0
	Total Cost	$45.1	$52.6	$121.7	$50.5	$60.4
Madison	Fuel	$28.7	$26.8	$25.1	$25.1	$27.3
	O&M	$5.2	$5.5	$7.6	$6.7	$4.9
	Capital Additions	$2.4	$1.7	$1.4	$0.2	$3.7
	Overheads	$1.0	$1.0	$1.4	$1.3	$0.9
	Total Cost	$37.3	$35.0	$35.5	$33.3	$36.8

Excluding years with extraordinary capital additions (indicated in bold in Table 28), the all-in cost of keeping Dolet Hills operating has been around $60/MWh–$80/MWh, while Rodemacher has cost $40/MWh–$60/MWh in various years. Madison has been a relative bargain, costing only about $35/MWh.

The capital additions, and hence the total costs, would generally be higher with the actual annual additions or expenditures, if those values were available.

F. Historical Market Prices for the Cleco Units

Q: What energy prices do the Cleco resources face in the MISO market?

A: Table 29 provides the average price for each Cleco coal-fired unit and for the Nesbitt gas-fired unit. I weighted the market energy price in each hour by the unit gross hourly output reported in the EPA AMPD database.

Table 29: Market Energy Prices Weighted by Gross Output

	Average Value of Energy Generated ($/MWh)		Gross Capacity Factor	
	2016	**2017**	**2016**	**2017**
Dolet Hills	$26.96	$31.58	46%	45%
Nesbitt	$33.32	$44.02	14%	10%
Rodemacher	$30.74	$31.77	42%	43%
Madison	$26.66	$30.75	69%	67%

As in Table 12 for the NRG resources, the general pattern in Table 29 is that higher capacity factors are associated with lower average prices. At one extreme, Nesbitt attempts to run only when prices are high, and its output has relatively high average energy values. The market energy price for Nesbitt is lower than the combustion turbines in Table 12, because Nesbitt cannot ramp up and down as fast as combustion turbines. At the other extreme, Madison runs nearly 70% of the time, and gets the lowest market prices for its energy.[74]

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

A: Table 30 summarizes that comparison. I started by estimating the short-run cost for each unit as the sum of 2017 fuel costs from Table 22 and EPA's forecast of variable O&M from Table 23. I then counted the number of hours in which the market energy price exceeded the short-run cost.

Table 30: Comparison of LMP to Fuel and Variable O&M by Unit (2017)

	Dolet Hills	Rodemacher	Madison
Fuel + VOM ($/MWh)	$52.3	$43.3	$33.3
When LMP exceeds Fuel + VOM			
Number of Hours	219	642	1,329
% of hours	3%	7%	15%

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

A: The units generated much more energy than they would have if they ran at full power in every profitable hour, and not in any unprofitable hour, as shown in Table 31.

[74] The energy value of the units also varies with whether they are available to operate at high-priced hours and other details of dispatch.

Table 31: Comparison of Profitable Hours to Capacity Factors, 2017

	Dolet Hills	Rodemacher	Madison
Profitable Hours	3%	7%	15%
Capacity Factor	39%	47%	72%
Difference	37%	40%	57%

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, the coal units cannot cycle up and down fast enough to run in all the profitable hours without running in unprofitable hours. Table 31 shows that all three units ran in many unprofitable hours.

Q: How do the market energy prices compare to the costs of keeping the coal units in operation?

A: Table 32 compares the publicly-reported total cost of each unit per kWh in 2017 (from Table 28) to the average LMP in the hours in which the unit operated (from Table 29).

Table 32: Comparison of LMP to Ongoing Costs ($/MWh)

	Energy Value		Total Cost		Profit or Loss	
	2016	**2017**	**2016**	**2017**	**2016**	**2017**
Dolet Hills	$27.0	$31.6	$66.6	$76.9	-$39.6	-$45.3
Rodemacher	$30.7	$31.8	$50.5	$60.4	-$19.8	-$28.7
Madison	$26.7	$30.8	$33.3	$36.8	-$6.6	-$6.1

Dolet Hills and Rodemacher were overwhelmingly unprofitable to operate, with Cleco's shares losing some $70 million running its shares of the units. Madison incurred a smaller loss of about $24 million. The results of similar comparisons will vary from year to year.

Q: Have other studies examined the recent economics of individual coal units?

A: Yes. The Bloomberg New Energy Finance ("BNEF") study, attached as Exhibit PLC-4, covered the six-year period of 2012 through 2017, for 903 units totaling 280 MW of nameplate capacity, excluding combined heat and power units.[75] 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 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 the Cleco coal units?

A: Table 33 provides BNEF's results for each of these units, for each year and cumulative for the period. BNEF provides estimates of short-run profit (energy revenues minus fuel and variable O&M) and long-run operating profit (all revenues minus all expenses, but excluding capital expenditures). It also provides data on environmental capital expenditures.

Table 33: BNEF Estimates of Cleco Coal Unit Margins ($M)

	2012	2013	2014	2015	2016	2017	2012-17
Dolet Hills (Cleco Share)							
Revenue	66.5	47.5	57.1	68.4	53.5	36.2	329.2
Expenses	103.3	84.5	74.8	106.4	90.7	56.0	515.8
Margin	-36.8	-37.0	-17.8	-38.1	-37.2	-19.9	-186.7
Env CapEx	3.4	0.0	0.0	0.0	1.1	0.0	4.5
BNEF net	-40.2	-37.0	-17.8	-38.1	-38.3	-19.9	-191.1
Rodemacher (Cleco Share)							
Revenue	23.8	28.3	27.5	21.2	19.1	20.1	140.0
Expenses	34.7	39.1	26.5	28.5	25.0	22.7	176.5
Margin	-10.9	-10.8	1.0	-7.3	-5.9	-2.6	-36.5
Env CapEx	0.9	4.8	7.4	1.2	0.6	0.0	14.8
BNEF net	-11.8	-15.6	-6.4	-8.6	-6.5	-2.6	-51.4
Madison							
Revenue	34.7	63.2	94.7	60.6	58.7	68.9	380.9
Expenses	55.5	83.1	81.5	76.6	73.6	69.2	439.4
Margin	-20.8	-19.9	13.2	-15.9	-14.9	-0.3	-58.5
Env CapEx	3.8	20.0	31.1	5.2	2.3	0.0	62.4
BNEF net	-24.5	-39.9	-17.9	-21.1	-17.2	-0.3	-120.9

According to BNEF, all three Cleco coal units had costs higher than revenues every year, and in total.

Q: In addition to regularly operating uneconomically, are there other economic risks related to the continued operation of Cleco Power's solid-fuel fleet?

A: Yes. As discussed, at least two of Cleco Power coal-fueled units—Dolet Hills and Rodemacher—are currently uneconomic to operate, and ratepayers would benefit from replacing those units with more efficient and lower-cost resources (including purchases on the MISO market). The proposed transaction, however, creates the risk that Cleco Power will not be able to access the additional equity required to replace those units. Continued operation of these units may require additional capital costs. The costs of which I am aware fall into two broad categories: (1) costs associated with the continued operation of the Dolet Hills mine, and (2) environmental compliance costs that could affect either or both units. The proposed transaction could make it more difficult for Cleco Power's parent company to raise the equity necessary to address either replacement or (if warranted) continued operation.

Q: What are the risks associated with the lignite mine?

A: The Dolet Hills power plant obtains some of its lignite from the adjacent Oxbow mine, and based on publicly available data it appears that Cleco

Power's costs for delivered fuel are already very high.[76] The owners expect that the current mine configuration will be sufficient to supply Dolet Hills' fuel needs until 2026.[77] If Dolet Hills is to continue operating, Cleco Power faces additional capital costs associated with expanding the mine, which would make this uneconomic plant even less desirable. In addition, the proposed transaction could make it more difficult for Cleco Power's parent company to raise the equity necessary to address those impending capital costs.

Q: What are the potential environmental compliance risks associated with Cleco Power's solid-fuel plants?

A: Based on publicly available testimony in Cleco's MATS retrofit docket, LPSC Docket No. U-32507, impending environmental regulations governing air quality, water quality, and coal combustion residual disposal could each impose moderate to significant capital costs at Cleco Power's older coal-fired

[76] Cleco and SWEPCo acquired the Oxbow mine in 2009 for $25.7 million.

[77] *See* Order No. U-30975 at 4, *In re: Joint Application of Cleco Power LLC and Southwestern Electric Power Company for: (I) Authorization to Enter into a Proposed Agreement with North American Coal to Purchase the Permit, Leases, and Reserves Associated with the Oxbow Mine* . . . . (Sept. 16, 2009); *see also* Oct. 10, 2013 Order, PUCT Docket 40443, Finding of Fact 140, *available at* http://interchange.puc.texas.gov/.

facilities.[78] Specifically, there are potential environmental compliance risks for Dolet Hills and/or Rodemacher associated with the Regional Haze Rule, the Coal Ash Combustion Residuals Rule, and the Effluent Limitations Guidelines for scrubber and ash handling wastewater, as well as potential carbon regulations.

Q: What are the implications of these regulations on these coal units?

A: Until the state or EPA determine compliance mechanisms for electric generating units, and until engineering estimates are developed, the exact timing and cost of complying with these rules is unknown. Based on the cost of compliant technologies at other plants, and in generic analyses, it appears that the capital costs of continuing to operate Dolet Hills and Rodemacher could be in the hundreds of millions of dollars.

Finally, although there is significant uncertainty surrounding potential carbon regulation, most utilities recognize that carbon emissions will be subject to regulation at some point in the relatively near future. Any carbon

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[78] *See* Direct Testimony of Dr. Jeremy I. Fisher (November 8, 2013), *In re* Application of Cleco Power LLC for: *(i) Authorization to Install Emissions Control Equipment at Certain of its Generating Facilities in Order to Comply with Federal National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units Rule; (ii)Authorization to Recover the Costs Associated with the Emissions Control Equipment in LPSC Jurisdictional Rates; and (iii) Expedited Treatment*, Docket No. U-32507 (order entered February 5, 2016).

tax or allowance scheme will further erode the economics of both the Cleco coal plants and the Big Cajun 2 coal units.

G. Summary

Q: What are your conclusions about the Cleco Power coal units?

A: I have determined that most of Cleco Power's existing solid-fuel fleet is uneconomic, would require capital improvements to keep operating, and is ripe for retirement. The financial burdens associated with this transaction create a risk that Cleco Corp will not be able to access or provide the additional equity that may be required to replace Cleco Power's aging and uneconomic generation, in addition to normal capital requirements and the occasional emergency. In this Application, Cleco Corp has stated that it wants to "commit to invest in the development and optimization of Louisiana's electric infrastructure…."[79] That is an admirable goal, and could justify Cleco Corp investing in Cleco Power (such as by purchasing the Bayou Cove and Cottonwood plants from NRG) and retiring uneconomic generators, but does not justify acquisition of a largely uneconomic merchant generation fleet.

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[79] Application at 6, 22; Direct Testimony of Shane Hilton at 12.

Q: Do you see any way to optimize the Cleco Power and Cleco Cajun fleets?

A: If the Commission is inclined to approve the transaction, it should condition such approval on steps to improve Cleco Power's generation fleet. As a first step, any approval should require the prompt retirement of the most uneconomic generation units: Big Cajun 2 Units 1 and 3, Dolet Hills and Rodemacher. Second, the Commission should ensure that ratepayers benefit directly from the transaction, such as using the cost-effective portion of the NRG portfolio (such as Cottonwood and Bayou Cove) to replace the uneconomic Cleco Power coal-fired plants, improve the Cleco Power supply mix, and reduce costs to ratepayers.[80] The Commission should not authorize the acquisition until ratepayer benefits have been demonstrated.

VI. Trends in Coal-Plant Retirements and Economics

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

A: Yes. M.J. Bradley & Associates analyzed the trends in the lifespan and size of coal retirements in a 2017 report. The Brattle Group conducted an analysis of coal-plant cost-effectiveness in 2018, but did not release results for

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[80] Ideally, the Commission would evaluate all of these options in an IRP, which may not be possible unless NRG and Cleco can agree to suspend the proposed transaction during the IRP proceeding.

individual units or plants. Both of these studies support the conclusions of the Cleco analysis of the NRG units, the BNEF analysis of the Cleco units, and the other evidence I provide above: most coal plants are uneconomic and plant operators choosing to retire their coal units earlier.

A. Retirement Trends

Q: Is there reason to believe that coal plants are being retired even than had been the case?

A: Yes. Over the past decade, younger and younger coal plants are being retired. An analysis by Lawrence Berkeley National Laboratory indicated that the median retirement age for coal units projected to shut down between 2017–2023 would be 40–50 years old, rather than the 50–60 years for units retired between 2010 and 2016.[81]

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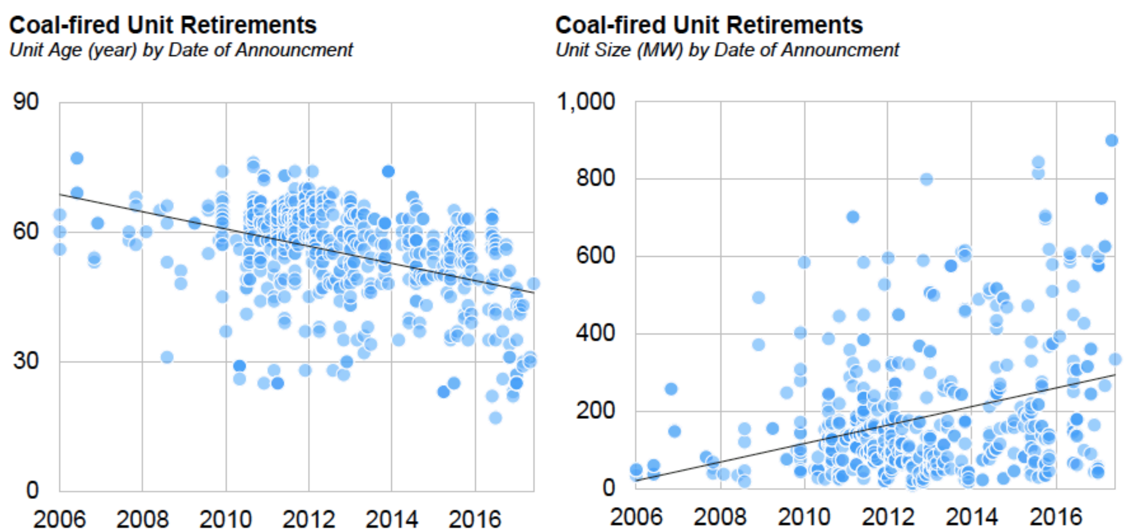
[81] Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, "Power Plant Retirements: Trends and Possible Drivers," Fig. 3 (Nov. 2017), https://emp.lbl.gov/sites/default/files/lbnl_retirements_data_synthesis_final.pdf.

M.J. Bradley & Associates also found that retirements are affecting larger and younger units over time:

> On average, units that announced plans to retire between 2010 and 2015 were 57 years old and only 166 MW. By contrast, units that have announced plans to retire since 2016 are only 42 years old and 336 MW on average.[82]

Figure 2 reproduces M.J. Bradley's analysis of the time trends in size and age of coal retirements.

Figure 2: Trends in Coal Unit Retirements: Age and Unit Size



[82] MJB&A Issue Brief, "Coal-Fired Electricity Generation in the United States and Future Outlook" (Aug. 28, 2017).

B. The Brattle Study of Coal-Plant Economics

Q: What were the results of the Brattle study?

A: The Brattle Group study, attached as Exhibit PLC-5, used ABB's Velocity Suite data to estimate the 2017 net margin for each domestic coal plant (as well as each nuclear plant).[83] Brattle does not identify the results for specific units, but does provide aggregate results, as summarized in Table 34.

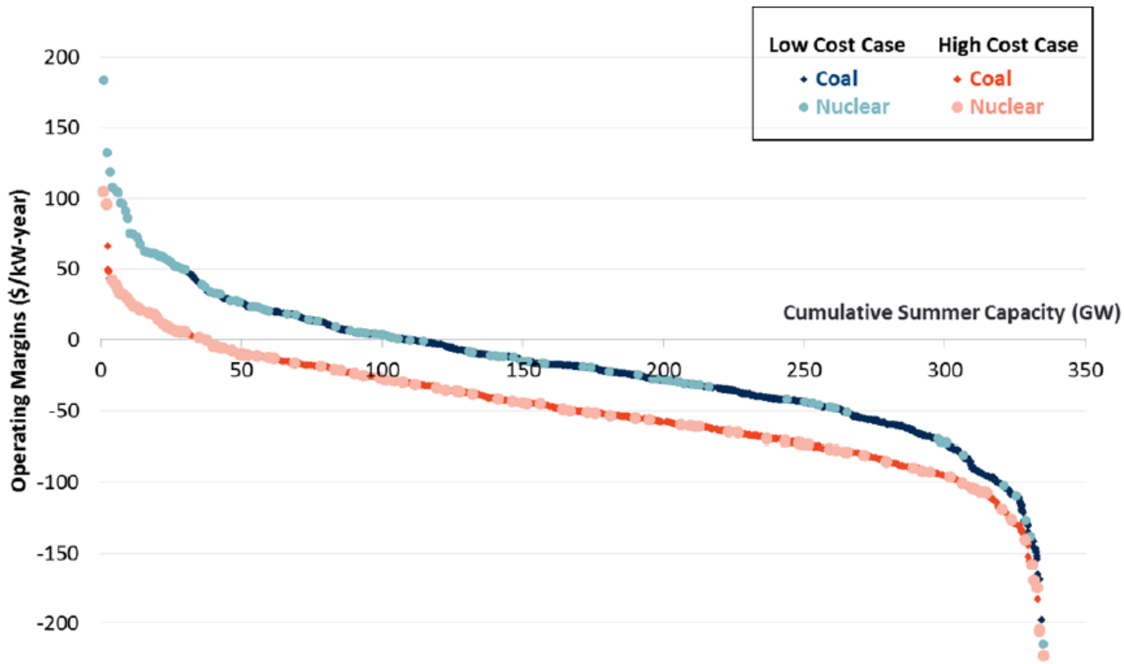
Table 34: Brattle Results for Coal Plant Economics, 2017

		Capacity with Revenue Shortfall			
		Gigawatts		Share 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 3.

[83] Metin Celebi, *et al*., The Cost of Preventing Baseload Retirements: A Preliminary Examination of the DOE Memorandum (Brattle Group 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 3: 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 Cleco and NRG coal units?

A: The average costs of the coal units in the Brattle analysis are listed in Table 35. Brattle used the unit-specific fuel and VOM costs from the ABB database, the generic FOM values from EPA that I discuss in Section V.B and the capital expenditure costs from EIA that I discuss in Section V.C.

Table 35: 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 Capital Expenditure	$4.97	$4.97
Total	$35.97	$40.69

The Dolet Hills and Rodemacher costs summarized in Table 28 are much higher than these Brattle estimates, while the Madison costs are close to Brattle's low-cost case.

VII. Brief Summary

Q: Please briefly summarize your conclusions.

A: As discussed above, I find:

a. This transaction imposes unacceptable risks to Cleco Power.

b. The NRG assets are significantly uneconomic and the profits on the wholesale contracts are insufficient to offset these losses and repay the purchase price.

c. Cleco Power's existing solid-fuel fleet is uneconomic.

d. Cleco Corp may not be able provide adequate financial support to Cleco Power (for replacement of uneconomic generation, system improvements, or storm-related repairs) if the proposed transaction is completed.

e. The Commission should reject the transaction as described in the Application.

f. The Commission should condition approval of any merger of the NRG resources into Cleco Corp on the retirement of the uneconomic units and on establishing a planning process to optimize the fleet.

Q: Does this conclude your testimony?

A: Yes.

BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

Application of Cleco Corporate Holdings LLC and Cleco Power LLC for: (I) Authorizations, Waivers, and Regulatory Interpretations of Certain Provisions of LPSC Order No. U-33434-A; (II) Authorization for Cleco Corporate Holdings LLC to Pledge its Ownership Interest in Cleco Power LLC; and (III) Expedited Treatment	)	**Docket No. U-34794**

AFFIDAVIT

Paul Chernick, being first duly sworn, deposes and says that he is the same Paul Chernick whose Direct Testimony accompanies this affidavit; that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth therein are true and correct to the best of his knowledge, information and belief; and that he does adopt the same as his sworn testimony in this proceeding.

Paul Chernick

Subscribed and sworn to before me on this 31st day of Aug, 2018

Notary Public

My Commission expires: 9/11/2020

Commonwealth of Massachusetts
On this 31st day of Aug, 2018
I certify that the above document is a true, exact, complete and unaltered copy of the original.

Dianne J. DeMarco, Notary Public
My Commission Expires September 11, 2020

CERTIFICATE OF SERVICE

I hereby certify that I have, on this 4th day of September, 2018, served copies of the foregoing document upon all other known parties of this proceeding via U.S. Priority Mail.

Lauren Hogrewe
Litigation Assistant
Sierra Club Environmental Law Program
2101 Webster St., Suite 1300
Oakland, CA - 94612-3011
415-977-5789
lauren.hogrewe@sierraclub.org