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EXHIBIT 7

DIRECT TESTIMONY OF ROBERT BREEDLOVE

ON BEHALF OF CLECO POWER LLC

REDACTED TO OMIT CONFIDENTIAL,
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AND PROPRIETARY INFORMATION PURSUANT
TO RULE 12.1 OF THE COMMISSION'S
RULES OF PRACTICE AND PROCEDURE

BEFORE THE
LOUISIANA PUBLIC SERVICE COMMISSION

EX PARTE: APPLICATION OF	)	
CLECO POWER LLC FOR	)	
AUTHORIZATION OF: (I) SITE	)	
SPECIFIC CONTRACT FOR LARGE	)	
LOAD CUSTOMER;	)	
(II) BRIDGE CAPACITY CONTRACT;	)	
(III) CONSTRUCTION OF NEW	)	DOCKET NO. U-_____
TRANSMISSION	)	
INTERCONNECTION;	)	
(IV) CONSTRUCTION OF NEW	)	
GENERATION; (V) ASSOCIATED	)	
WAIVERS; AND (VI) EXPEDITED	)	
TREATMENT.	)	

DIRECT TESTIMONY

OF

ROBERT BREEDLOVE

ON BEHALF OF

CLECO POWER LLC

JULY 1, 2026

**CLECO POWER LLC
DIRECT TESTIMONY OF ROBERT BREEDLOVE
LPSC DOCKET NO. U-_____**

EXHIBITS

EXHIBIT NO.	DESCRIPTION
Exhibit RB-1 (HSPM)	Useful Life Assessment Report
Exhibit RB-2	Cleco Power Letter to LDEQ Regarding Rodemacher 2
Exhibit RB-3	LDEQ Response Letter
Exhibit RB-4 (HSPM)	Project Schedule

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I. INTRODUCTION AND BACKGROUND

Q1: PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A: My name is Robert Breedlove. I am the Chief Operations Officer of Cleco Corporate Holdings LLC ("Cleco Corp"), which is the parent holding company of Cleco Power LLC ("Cleco Power" or the "Company"). My business address is 2030 Donahue Ferry Road, Pineville, Louisiana, 71360.

Q2: PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES.

A: As Chief Operations Officer, I oversee generation operations, engineering and construction, asset management, and transmission services of Cleco Power, an electric public utility regulated by the Louisiana Public Service Commission ("LPSC" or the "Commission").

Q3: PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL HISTORY.

A: In 1996, I earned a Bachelor of Science degree in Mechanical Engineering from Mississippi State University. In 2008, I was awarded a Master of Business Administration degree from Tulane University.

Between 1996 and 2000, I was employed by a major U.S.-based petrochemical company in a project engineering role for development of electric power and utilities projects throughout the company's facilities worldwide. In 2000, I joined Entergy Gulf States, Inc. as a Plant Engineer at a gas turbine facility. From 2004 through 2010, I transitioned first to Entergy Mississippi, Inc., serving as Process Superintendent and then later to Production Superintendent for Entergy Louisiana, LLC where I was responsible for three gas turbine-powered plants in northern Louisiana. In 2010, I was named Asset Manager for Entergy Louisiana, LLC's Acadia Power Block Two. In 2012, I was named Fleet Maintenance

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1 Manager for Entergy Services, Inc. ("ESI"), with responsibility for managing strategic
2 initiatives for a fleet of gas turbine plants, each respectively owned and operated by one of
3 Entergy Corporation's five regulated electric utilities. In 2012, I was named Director of
4 Plant Support, and in 2016, I was named Director of Fleet Maintenance in Power
5 Generation. In 2021, I transitioned to Cleco Corp and was named Vice President of
6 Generation Operations for Cleco Cajun LLC and Cleco Power. I was appointed to my
7 current position, Chief Operations Officer of Cleco Corp, in January 2024.

8 **Q4: HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE THE LPSC?**

9 **A:** Yes, I have previously provided testimony before the Commission while employed by ESI.
10 I provided testimony on behalf of ELL in (i) LPSC Docket No. U-32759, *In Re: Application*
11 *on Behalf of Entergy Gulf States Louisiana, L.L.C. for an Accounting Order and*
12 *Declaratory Relief Relating to the Commission's General Order Dated November 6, 1997*
13 *Governing the Treatment and Allocation of Fuel Costs*; and (ii) LPSC Docket No. U-33770,
14 *In Re: Joint Application of Entergy Louisiana, LLC, Entergy Gulf States, L.L.C., and*
15 *Entergy Louisiana Power, LLC for Approval to Construct St. Charles Power Station, and*
16 *for Cost Recovery*. I also testified previously while with ESI before the City Council of
17 New Orleans on behalf of Entergy New Orleans, LLC in Docket Nos. (i) UD-16-02, *In Re:*
18 *Application of Entergy New Orleans, Inc. for Approval to Construct New Orleans Power*
19 *Stations and Request for Cost Recovery and Timely Relief*; and (ii) UD-18-07 *In Re:*
20 *Application for a Change in Electric and Gas Rate in the City of New Orleans*.

21 **Q5: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

22 **A:** My testimony supports the Company's application (the "Application") in this proceeding.
23 The Application seeks, among other things, the approval of an Electric Service Agreement

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1 (“ESA”) that is a Site Specific Contract and related agreements with Applied Digital
2 Corporation (the “Customer”); approval to enter into a capacity agreement with Tenaska
3 Frontier Partners, Ltd. (the “Capacity Agreement”); approval of or exemption for
4 construction of transmission interconnection infrastructure to serve the load required by a
5 new, \$3.6 billion hyperscale data center to be developed by Applied Digital Corporation
6 (the “Customer”) in Rapides Parish, Louisiana (the “Project”);¹ and approval of the
7 Company’s construction of new generation infrastructure to serve Cleco Power’s existing
8 and future customer load.

9 Cleco Power’s Application describes its prayers for relief; however, my direct testimony
10 will focus on Cleco Power’s generation-related needs to reliably serve the Company’s
11 customers. Specifically, I will describe the Company’s current generation resources, some
12 of which are reaching the end of their useful lives and are subject to certain operational and
13 environmental policy risks; the need for additional generation resources in light of resource
14 planning matters discussed further by Company witness Richard Sharp; the possible
15 repowering of existing Cleco Power generating resources; details outlining Cleco Power’s
16 proposed new generation project, which is necessary to reliably serve Cleco Power’s
17 existing customers as well as the Project; challenges in the current market; and actions the
18 Company is taking to address uncertainties regarding the proposed new generator. On this
19 last point, Company witness Jonathan Long also addresses the current state of the market.

20 **Q6: HOW IS YOUR TESTIMONY ORGANIZED?**

¹ See Louisiana Economic Development, *Central Louisiana Secures \$3.6 Billion Applied Digital AI Factory Campus* (May 26, 2026) <https://www.opportunitylouisiana.gov/news/central-louisiana-secures-3-6-billion-applied-digital-ai-factory-campus>.

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A: My testimony is organized into the following broad topics:

1. Cleco Power's current generation resources;
2. The need for a new combined cycle gas turbine ("CCGT") generator to ensure reliable service and its associated estimated cost and schedule;
3. Cleco Power's generation procurement and contracting strategy amidst current market conditions and industry challenges in generation construction;
4. A proposed quarterly monitoring plan; and
5. Construction risk mitigation.

II. CLECO POWER'S EXISTING GENERATION RESOURCES

Q7: PLEASE LIST CLECO POWER'S EXISTING GENERATION RESOURCES.

A: Cleco Power currently owns and operates the generation resources listed in Table 1, below.

Table 1. Existing Cleco Power Generators.²

Unit	Fuel Type	Net Capacity
Nesbitt 1	Natural Gas	429 MW
Rodemacher 2	Powder River Basin ("PRB") Coal	146 MW ³
Madison 3	Petcoke/Coal	634 MW
Acadia Unit 1	Natural Gas	553 MW
Coughlin 6	Natural Gas	248 MW
Coughlin 7	Natural Gas	479 MW
Teche 4	Natural Gas	34 MW
St. Mary Clean Energy Center	Waste Heat	40 MW

² Net Capacity (MW) values were pulled from the Securities Exchange Commission ("SEC") combined 10-K filing for Cleco Corp and Cleco Power for 2025 and reflect Generator Verification Test Capacity ("GVTC"); see <https://www.sec.gov/ix?doc=/Archives/edgar/data/18672/000108981926000002/cnl-20251231.htm>.

³ Cleco Power owns 30%, the City of Lafayette and its municipal utility owns 50%, and Louisiana Energy and Power Authority ("LEPA") owns the remaining 20%.

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1 All told, Cleco Power currently owns and operates 2,563 MW of total net capacity.
2 Furthermore, a new solar photovoltaic ("PV") facility is currently under construction in
3 DeSoto Parish, Louisiana, which will provide 240 MW of solar power to Cleco Power
4 pursuant to the terms of an Amended and Restated Solar Power Purchase Agreement,
5 authorized by the Commission in LPSC Order No. U-36502, dated October 8, 2024. The
6 solar PV facility is anticipated to enter commercial operation in late 2026. For further
7 details regarding Cleco Power's generation resources and long-term planning processes,
8 please refer to the direct testimony of Cleco Power's witness Mr. Sharp who addresses the
9 Company's integrated resource planning ("IRP") efforts.

10 **Q8: PLEASE PROVIDE ADDITIONAL DETAIL CONCERNING THE COMPANY'S**
11 **CURRENT GENERATION RESOURCES.**

12 **A:** As shown in Table 1, Cleco Power owns and operates a diverse array of generation
13 resources totaling approximately 2,563 MW of net capacity. Notably, approximately one-
14 third of this capacity comes from generating resources that have been in service for between
15 43 and 64 years. As described in Cleco Power's most recent Interim Integrated Resource
16 Plan ("Interim IRP")⁴ report discussed by Mr. Sharp, the Company expects that 567 MW
17 of this older generation will be retired over the next decade. Below I discuss the risks and
18 uncertainties involved with the Company's aging generation fleet. I also address key U.S.
19 Environmental Protection Agency ("EPA") rules and requirements that affect several Cleco
20 Power generation units and may require the Company to either repower or retire certain
21 units over the coming years.

⁴ Cleco Power's Interim IRP was filed in LPSC Docket No. I-37725 and has been consolidated into Cleco Power's most recent IRP in LPSC Docket No. I-37765.

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1 As outlined above, Cleco Power's current generation portfolio consists of: (i) three
2 combined cycle gas units with a total capacity of 1,280 MW; (ii) two solid-fuel-fired steam
3 units collectively providing 780 MW; (iii) one natural gas steam unit rated at 429 MW; and
4 (iv) two units each under 50 MW—one being a small black-start natural gas unit (34 MW)
5 and the other utilizing waste heat recovery (40 MW) from a co-located industrial facility
6 for power generation.

7 **Q9: PLEASE DESCRIBE THE OVERALL CONDITION OF THESE RESOURCES**
8 **ALONG WITH THE COMPANY'S PLANS FOR THESE RESOURCES FOR THE**
9 **FORESEEABLE FUTURE.**

10 **A:** Below I will describe the condition of each generation resource in detail as well as the
11 potential for the unit in question to be repowered or even retired depending on the
12 circumstances.

13 **A. CCGT Resources**

14 Acadia Power Station ("Acadia") is a CCGT, natural-gas-fired generator equipped with
15 selective catalytic reduction ("SCR") systems for nitrogen oxide ("NOx") emissions
16 control. Acadia began operation in 2002 and is in good overall condition. Major systems
17 and equipment have been maintained in accordance with prudent utility practice. Acadia
18 is expected to maintain high availability and reliability, assuming sound maintenance
19 practices continue. I should also note that Acadia has two generating units, with Cleco
20 Power owning Power Block 1 and Entergy Louisiana, LLC owning Power Block 2. Cleco
21 Power operates both power blocks and provides staffing for maintenance and other
22 activities necessary for reliable and safe operations.

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1 The repowered Coughlin Power Station (“Coughlin”) is a CCGT, natural-gas-fired
2 generator equipped with SCR systems. Coughlin began operations in 2000 in its repowered
3 configuration and is in good overall condition. Major systems and equipment have been
4 maintained in accordance with good utility practice. Coughlin Unit 6 was recommissioned
5 in 2000 with a new combustion turbine (“CT”) and a heat recovery steam generator
6 (“HRSG”), although its steam turbine (“ST”) was originally commissioned in 1961 and
7 has been in service for 65 years. Based on information included in a report commissioned
8 by the Company, only three percent of STs comparable in age to Coughlin Unit 6 remain
9 in service.⁵ The ST for Coughlin Unit 7 was originally commissioned in 1964 and has been
10 in service for more than 60 years. Only nine percent of STs comparable in age to Coughlin
11 Unit 7 remain in service.⁶

12 **B. Solid Fuel Resources**

13 Rodemacher 2 is a co-owned, solid-fuel-fired generator at the Brame Energy Center
14 (“Brame”) equipped with an electrostatic precipitator, a fabric filter baghouse, low NOx
15 burners, selective non-catalytic reduction (“SNCR”), dry sorbent injection (“DSI”), and
16 activated carbon injection (“ACI”) systems. Rodemacher 2 entered commercial operation
17 in 1982. Major systems and equipment have been maintained in accordance with good
18 utility practice. Rodemacher 2 is expected to maintain high availability and reliability,
19 assuming sound maintenance practices are continued. However, the unit is subject to the
20 U.S. EPA Coal Combustion Residuals (“CCR”) Rule finalized in 2020 and Effluent
21 Limitation Guidelines and Standards (“ELG”), which in aggregate previously required that

⁵ See Exhibit RB-1, at p. 16. Exhibit RB-1 contains Highly Sensitive Protected Materials (“HSPM”).

⁶ See Exhibit RB-1 (HSPM), at p. 16.

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1 Rodemacher 2 must cease coal-fired operations by 2028, or alternatively install costly
2 equipment that likely may not be cost-effective given the age and condition of the unit. I
3 say previously, however, because the U.S. EPA published a final rule on December 31,
4 2025, revising the ELGs to provide for site-specific extensions to facilitate an alternative
5 compliance path. The new ELG deadline extension rule enables permitting authorities to
6 grant site-specific deadline extensions, including for transfers and compliance deadlines.

7 Since then, Cleco Power submitted the required initial request letter to the Louisiana
8 Department of Environmental Quality ("LDEQ") seeking (1) an extension of the December
9 31, 2025, deadline to transfer out of the 2028 ELG coal cessation subcategory, pursuant to
10 40 C.F.R. § 423.18(d)(2), and (2) an extension of the December 31, 2025, deadline to
11 comply with the generally-applicable bottom ash transport water ("BATW") limitations on
12 discharges to 10% of the bottom ash system volume, pursuant to 40 C.F.R. § 423.18(d)(1).

13 Please refer to Exhibit RB-2 for a copy of the initial request letter that Cleco Power sent to
14 the LDEQ. On April 23, 2026, Cleco Power received a letter from the LDEQ indicating
15 no opposition to extending the December 31, 2025, deadline to transfer out of the 2028
16 ELG coal-cessation subcategory, as well as the December 31, 2025, deadline to comply
17 with the generally applicable BATW limitation requiring discharges to be limited to 10%
18 of the bottom ash system volume. The LDEQ also approved Cleco Power's proposed
19 compliance schedule. A copy of the LDEQ approval letter sent to Cleco Power is attached
20 as Exhibit RB-3.

21 As noted, Rodemacher 2 is subject to the U.S. EPA's CCR Rule finalized in 2020, which
22 governs coal ash disposal. Due to CCR Rule requirements, the plant's useful life
23 expectancy was changed to the end in 2028, because the CCR Rule mandated closure of

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1 the plant's fly ash and bottom ash impoundments; without the U.S. EPA's CCR Rule,
2 operation of Rodemacher 2 could have continued beyond 2028. Note, however, that in
3 February 2026, the U.S. EPA issued a proposed rule to extend the CCR Rule compliance
4 deadline to October 17, 2031, which expressly applies to Rodemacher 2; however, that rule
5 has not been finalized at this time and may be subject to court challenges.

6 Rodemacher 2 has been operating for 44 years, and only 25% of comparable generating
7 units remain online for up to 41 years of operations.⁷ The unit has already surpassed its
8 originally designed operating hours by approximately 33%. Given the LDEQ's compliance
9 extension approvals, Rodemacher 2's useful life could be extended to 2035 with some
10 modifications to and capital investments in the unit. However, Cleco Power only owns
11 30% of the Rodemacher 2 unit, and all Rodemacher 2 Joint Owners will need to agree on
12 any plan that would affect the nature of the unit or otherwise alter its expected remaining
13 useful life while remaining compliant with the applicable ELG regulations and the CCR
14 Rule. As a part of its plan to retain as much accredited capacity as possible for its
15 customers, Cleco Power along with the other Joint Owners are currently considering one
16 of two potential compliance paths: (1) ceasing coal combustion and converting the unit to
17 natural gas operation by the end of 2029, or alternatively, (2) continuing coal combustion
18 beyond 2029. As such, the two extensions that LDEQ has granted as described above are
19 necessary to give the Joint Owners time to implement projects to complete the gas
20 conversion project or, alternatively, to comply with CCR and ELG regulations. Either path
21 will require additional capital investments and increased operations and maintenance

⁷ See Exhibit RB-1 (HSPM), at p. 13.

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1 (“O&M”) expenditures going forward. Consistent with applicable LPSC General Orders,
2 Cleco Power anticipates making a separate regulatory filing with the Commission once a
3 decision is made on what path the Company plans to follow.

4 Madison 3 is a solid-fuel-fired circulating fluidized bed (“CFB”) generator also located at
5 Brame. The unit is equipped with a fabric filter baghouse and limestone bed injection,
6 SNCR, and recirculating dry FGD systems. Madison 3 began operations in 2010 and is
7 equipped with state-of-the-art technology that provides an efficient heat rate and low air
8 emissions. Major systems and equipment have been maintained in accordance with good
9 utility practice. Madison 3 is expected to maintain high availability and reliability,
10 assuming sound maintenance practices continue. As I discuss further in my testimony
11 below, Cleco Power is subject to U.S. EPA’s Clean Air Act Section 111(d) Best System of
12 Emission Reduction (“BSER”) requirements, finalized in 2024, which establish various
13 federal guidelines for states to set greenhouse gas (“GHG”) emissions limits for certain
14 fossil fuel-fired power plants. Madison 3 is subject to 111(d) and must make operational
15 changes to continue operation beyond December 31, 2031. As such, the Company is
16 currently assessing the potential to co-fire natural gas in Madison 3, which would allow for
17 greater fuel flexibility and enable the unit to remain online beyond December 31, 2031, in
18 accordance with BSER requirements. It should be noted, however, that on June 17, 2025,
19 the U.S. EPA issued a proposed rule to repeal all greenhouse gas emissions standards for
20 fossil fuel-fired power plants (90 Fed. Reg. 25,752 (2025)); the repeal would impact
21 Madison 3, but the repeal will be subject to legal challenges.

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C. Natural Gas – Steam Resource

Nesbitt Unit 1 (“Nesbitt 1”) is a natural-gas-fired generator located at Brame. Nesbitt 1 began operations in 1975. Major systems and equipment have been maintained in accordance with good utility practice. Nesbitt 1 is expected to maintain high availability and reliability assuming sound maintenance practices continue. Nesbitt 1 has been operational for more than 50 years. Approximately 50% of generating units comparable to Nesbitt 1 remain operational beyond 55 years, and 25% remain in service beyond 63 years.⁸ Consistent with the Company’s long-term planning efforts and its IRP, which Mr. Sharp discusses in detail, Nesbitt 1 is projected to retire by 2035 when it reaches 60 years of operational age.

D. Other Resources

Teche Unit 4 (“Teche 4”) is a small natural-gas-fired generator with black-start capability. Teche 4 began operations in 2011 and is in good overall condition. The CT, originally placed in service in 1992 by another utility, was refurbished and restored to zero operating hours before being acquired and installed at its present location by Cleco Power. Major systems and equipment have been maintained in accordance with good utility practice. Teche 4 is expected to maintain high availability and reliability, assuming sound maintenance practices continue, although Teche 4 operates infrequently given the unit’s operational profile and variable costs.

St. Mary Clean Energy Center (“St. Mary CEC”) includes a waste heat recovery steam generator, steam turbine generator, and ancillary balance of plant equipment. The facility

⁸ See Exhibit RB-1 (HSPM), at p. 12.

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1 generates power through waste heat recovered from Cabot Corporation's adjacent carbon
2 black manufacturing facility. St. Mary CEC began operations in 2019 and is in good
3 overall condition. Major systems and equipment have been maintained in accordance with
4 prudent utility practice. St. Mary CEC is expected to maintain high availability and
5 reliability, assuming sound maintenance practices continue.

6 **Q10: PLEASE SUMMARIZE THE STATUS OF CLECO POWER'S EXISTING**
7 **GENERATION FLEET.**

8 **A.** In summary, the condition of Cleco Power's generation fleet demonstrates Cleco Power's
9 strong commitment to maintaining high availability and reliability across all units,
10 achieved through consistent adherence to good utility practices and ongoing maintenance
11 projects. While several units, such as Acadia, Coughlin 6 and 7, Madison 3, Teche 4, and
12 St. Mary CEC, are in good overall condition and expected to continue reliable operations
13 through the end of their useful lives, the Company is proactively addressing challenges
14 posed by aging infrastructure and evolving environmental regulations. For example, as
15 noted above, Rodemacher 2 faces imminent regulatory-driven changes as well as has
16 experienced a decline in its performance, both prompting consideration of either
17 conversion to co-firing with natural gas or targeted investments to extend its useful life.
18 Similarly, Madison 3 may transition to co-firing natural gas to comply with U.S. EPA
19 standards. Nesbitt 1, although reliable, is projected to retire within the next decade due to
20 its age. Overall, Cleco Power's strategic approach ensures that its diverse portfolio remains
21 flexible and robust to meet the needs of its customers today, and with investment in new
22 resources including the proposed new CCGT generator, Cleco Power will be well
23 positioned into the future to meet the needs of the Company's customers.

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**Q11: PLEASE DESCRIBE THE PROJECT'S LOAD ADDITION IN RELATION TO
CLECO POWER'S CURRENT GENERATION RESOURCES.**

A: Should the Commission approve the Application, the Customer will require up to 430 MW of reliable power. Mr. Sharp forecasts that the Project would represent a significant increase in Cleco Power's current peak load and annual energy (MWh) sales. As is discussed in detail by Mr. Sharp, Cleco Power must receive approval for the capacity purchase agreement with Tenaska Frontier Partners, Ltd. (the "Capacity Agreement"), which will provide capacity when the Customer begins taking service next year. However, the Company will need to construct additional generation to serve Cleco Power's customers, including the Project. Mr. Sharp discusses the Company's IRP and the identified need for new capacity to support the Company's customers, including the Customer's new data center, and address the Company's aging generation fleet and planned retirements that will occur within the next 10 years.

III. PROPOSED GENERATION RESOURCE

**Q12: PLEASE PROVIDE AN OVERVIEW OF THE PROJECT AND HOW CLECO
POWER PLANS TO SERVE ITS CUSTOMERS, INCLUDING THE PROJECT.**

A: As discussed further by Company witness Austin Finn, the Project is a hyperscale data center planned by the Customer, which is being constructed in Rapides Parish, Louisiana. Construction on the site began in January 2026 with permanent power service expected to begin mid-2027, and with the Customer reaching its full capacity in 2028. As Mr. Sharp explains, Cleco Power's long-term planning and related IRP efforts are designed to proactively address challenges I discuss above from aging generation and changing environmental regulations so the Company can continue to provide safe, reliable, and

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1 affordable service for all customers. Given these factors along with increased load and the
2 uncertainties and risks that long-term resource planning is intended to address, Cleco
3 Power believes that building a new gas-fueled CCGT generation resource is the optimal
4 course of action.

5 The proposed new CCGT generator will interconnect to a new substation that is in
6 proximity to the Project, as well as to the Company's transmission system and other
7 Company-owned generators. Company witness Christopher Thibodeaux addresses the
8 CCGT's transmission interconnection and the potential costs to interconnect to the
9 Company's transmission system. Mr. Thibodeaux also addresses transmission planning
10 and the processes the Midcontinent Independent System Operator, Inc. regional
11 transmission organization ("MISO") follows for load additions such as the Project and the
12 Company's proposed new CCGT generator. Finally, Mr. Thibodeaux addresses MISO's
13 Expedited Resource Addition Study ("ERAS") process, through which MISO is currently
14 evaluating the proposed new CCGT generator.

15 **Q13: PLEASE DESCRIBE THE NEW GENERATION RESOURCE PROPOSED BY**
16 **CLECO POWER INCLUDED IN THIS APPLICATION.**

17 **A:** The Company is seeking approval from the Commission under applicable General Orders,
18 discussed further by Company witness D. Andrew Owens, to build a single 756 MW CCGT
19 generator, which as I noted above is currently going through MISO's ERAS process.⁹ As
20 Mr. Sharp addresses in his testimony, the proposed new CCGT generator is necessary to
21 reliably serve Cleco Power's load and energy requirements, taking into account

⁹ Cleco Power submitted the proposed 756 MW CCGT generator into MISO's ERAS process on September 19, 2025, as Project Number E0048.

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1 transmission losses and MISO's Planning Reserve Margin Requirement ("PRMR"). Mr.
2 Sharp also discusses MISO- and Commission-imposed capacity obligations and how the
3 proposed new generator will help the Company meet its PRMR. The addition of the CCGT
4 generator aims to support the ongoing needs of Cleco Power's existing customers, help
5 serve the Customer's new data center load, and address the Company's aging generation
6 fleet and the risks and uncertainties posed by several generators nearing the end of their
7 useful lives and taking into account applicable U.S. EPA rules. In addition to overall
8 portfolio considerations, the proposed new generator must be sited in a specific area to
9 maintain system reliability within the Central Louisiana region, as discussed by Mr.
10 Thibodeaux.

11 The Company's current plan for the proposed CCGT generator is for 756 MW of generating
12 capacity. While the design has not yet been finalized, the unit is expected to be comprised
13 of one advanced-class combustion turbine, one HRSG with duct-firing and an SCR, and
14 one steam turbine generator ("STG") in a 1x1 combined cycle configuration, as I explain
15 further below. The facility will include associated balance of plant equipment, such as a
16 water-cooled condenser ("WCC") for closed-cycle cooling operations. Notably, the
17 generator design is expected to allow for hydrogen co-firing capabilities, and real estate at
18 the site will be reserved for future carbon capture equipment if that is required at some
19 point in the future.

20 **Q14: DOES CLECO POWER HAVE EXPERIENCE CONSTRUCTING AND**
21 **OPERATING POWER PLANTS?**

22 **A:** Yes. Cleco Power has substantial experience developing, constructing, owning, and
23 operating major generation facilities. Through an unregulated former subsidiary, the

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1 Company constructed the Acadia and Coughlin CCGT facilities, and Cleco Power has
2 operated both facilities since acquiring them. That operating experience includes
3 performing preventive maintenance, frequent engagement with turbine original equipment
4 manufacturers (“OEMs”), and administration of long-term service agreements.

5 Cleco Power also has established relationships with major engineering, procurement, and
6 construction (“EPC”) contractors and other key vendors. In addition, the Company
7 constructed the Teche 4 combustion turbine in 2011 and has owned and maintained that
8 unit since it entered service. Although Madison 3 uses different technology, the Company
9 also constructed that unit, which entered commercial service in 2010 and was a complex
10 major generation project. Finally, Cleco Power has employees with relevant project
11 development and construction experience and has retained an Owner’s Engineer (“OE”) to
12 assist with vendor evaluation and selection, technical matters, and construction oversight.

13 **Q15: WHY DID CLECO POWER SELECT A CCGT FOR ITS NEW GENERATOR?**

14 **A:** CCGT technology offers reliable, efficient electricity generation in all hours and is widely
15 recognized in the industry as the leading option for new baseload and load-following
16 generation. As I noted earlier, Mr. Sharp addresses the Company’s long-term resource
17 planning efforts and discusses why a CCGT generator is the optimal solution under the
18 circumstances relative to other resource options.

19 **Q16: WHAT ARE THE MAJOR COMPONENTS OF A TYPICAL CCGT FACILITY?**

20 **A:** A CCGT generator is made up of several key parts:

- 21 1. Combustion Turbine – This main engine burns clean natural gas to turn a generator,
22 create electricity, and expel hot exhaust gas. The turbine features a compressor and
23 combustion chamber, and the turbine itself operates in a similar manner to a jet

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1 engine. Air is drawn in and compressed by the compressor, then moved to the
2 combustion chamber where fuel is mixed in and ignited. The resulting high-
3 temperature gases expand through the turbine, generating mechanical energy that
4 powers an electrical generator, as explained below.

5 2. HRSG – Once the exhaust gases exit the gas turbine, the gases are sent to the HRSG,
6 which captures leftover heat to produce steam. Also located within the HRSG is
7 the post-combustion final air emission controls.

8 3. STG – The steam from the HRSG powers a steam turbine. As steam expands
9 through this turbine, it creates additional electricity, boosting overall efficiency.

10 4. Generator(s) – The generator is connected to the gas and steam turbines, either a
11 single generator coupled to both turbines or each turbine having its own generator.
12 The generator converts the turbines' mechanical energy into electrical energy and
13 is linked to the transmission grid via a substation.

14 5. WCC – This part condenses steam back into water after it leaves the steam turbine.
15 Using water to cool and condense the steam increases the system's overall
16 efficiency.

17 6. Auxiliary systems – These systems include fuel supply equipment, systems for
18 treating water used in steam production, and air emission controls to comply with
19 U.S. EPA and state environmental standards.

20 **Q17: PLEASE EXPLAIN HOW A CCGT FACILITY OPERATES.**

21 **A:** CCGT generators use the combination of a Brayton Cycle (the gas turbine) and a Rankine
22 Cycle (the steam turbine) to maximize the available energy released from the combustion
23 of the fuel, in this case natural gas. A CCGT generator maximizes efficiency by converting

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1 the energy in the exhaust gas into steam as the driver of a steam turbine; otherwise, the
2 energy in the flue gas would be released into the air. In other words, a CCGT generator
3 uses the gas turbine itself, along with steam created by the waste heat from the gas turbine,
4 to drive a generator that produces electricity. A CCGT generator is considered a highly
5 efficient power source because it features a HRSG, which captures exhaust heat from the
6 turbine to generate steam and, consequently, more electricity for the same amount of energy
7 input. Running combustion turbine generators ("CTGs") in a combined cycle arrangement
8 is a well-established method that not only maximizes fuel-to-power conversion efficiency,
9 which lowers emissions on a lb/MWh basis, but also enables flexible, automatic load-
10 following generation control. This configuration allows CTGs to shut down and restart
11 quickly when needed.

12 **Q18: PLEASE DISCUSS THE BENEFITS PROVIDED BY A CCGT GENERATOR.**

13 **A:** A CCGT generator can reach full power in just a few hours after startup, offering valuable
14 flexibility for dispatch operations. In addition, the efficiency (*i.e.*, heat rate) of this
15 technology materially outperforms early 2000-vintage CCGTs like the Company's Acadia
16 and Coughlin generators. Furthermore, since CCGT technology relies on clean natural gas
17 (which contains only a minimal amount of sulfur), a CCGT generator generates negligible
18 sulfur dioxide emissions. Compared to legacy fossil-fueled generators, a new highly
19 efficient CCGT generator will emit significantly less greenhouse gas emissions on a
20 lb/MWh-basis. Looking ahead, the potential capability to co-fire hydrogen, which would
21 release no carbon dioxide, will further enhance this unit's emissions profile, assuming
22 hydrogen fuel can be economically supplied to the facility. To be clear, the Company has

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1 no immediate plans to co-fire hydrogen but will design the facility to allow for the
2 possibility should that become feasible and economically attractive in the future.

3 **Q19: DOES THE COMPANY HAVE EXPERIENCE WITH OWNING AND**
4 **OPERATING A CCGT GENERATOR?**

5 **A:** Yes. As I discussed above, the Company currently owns and operates two CCGT facilities:
6 Acadia and Coughlin. Both facilities were constructed in the early 2000s, and the
7 Company has owned and operated both since acquiring them from affiliates. Although not
8 a CCGT generator, I note above that the Company constructed the Teche 4 combustion
9 turbine in 2011 and has owned and maintained the unit since it went into service.

10 **Q20: PLEASE EXPLAIN HOW THE AMBIENT ENVIRONMENT AND OTHER**
11 **FACTORS POTENTIALLY IMPACT THE CAPACITY OF A CCGT FACILITY.**

12 **A:** The maximum output of a CCGT unit can change due to factors like ambient temperature,
13 relative humidity, the heat (Btu) content of the fuel used, and how many operating hours
14 have passed since the last maintenance outage. For example, when the equipment is new,
15 a CCGT generator such as the Company is proposing in this Application would be expected
16 to produce about 756 MW under conditions of 59°F and 60% relative humidity. In contrast,
17 during summer with higher temperatures of 97°F and 56% relative humidity, some duct-
18 firing would be needed for the CCGT generator to maintain the same 756 MW of output.

19 **Q21: WHAT OTHER RESOURCE OPTIONS DID CLECO POWER CONSIDER?**

20 **A:** Mr. Sharp addresses the Company's long-term planning efforts, its IRP, what other resource
21 options were considered, and why those other options were not selected to meet the
22 Company's capacity needs.

23 **Q22: DOES A CCGT GENERATOR HAVE ANY LIMITATIONS?**

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1 **A:** Yes. All resource options possess inherent potential limitations, including CCGT
2 generators. Potential limitations include the following:

3 1. Reliance on Natural Gas – The proposed new CCGT generator will be designed to
4 use natural gas (although it will be capable of co-firing with hydrogen) and,
5 therefore, will be dependent on natural gas supply, exposing the Company and its
6 customers to fluctuations in fuel pricing and potential supply constraints. Later in
7 my testimony I discuss Cleco Power's strategy for securing natural gas delivery to
8 the CCGT generator.

9 2. Greenhouse Gas and Other Air Emissions – Although a CCGT generator will emit
10 significantly less criteria pollutants like sulfur dioxide and less than half the carbon
11 dioxide versus a coal-fired unit, it will still produce nitrogen oxides, carbon dioxide,
12 and other emissions and is subject to U.S. EPA and state oversight. The Company
13 has also set aside sufficient space for future carbon capture equipment if regulations
14 require it in the future.

15 3. Water Consumption – a CCGT generator requires water for both cooling and steam
16 generation processes. The Company will pursue applicable permits from the LDEQ
17 similar to the permits that have been obtained to construct and operate the
18 Company's other generators.

19 4. Capital Investment – The construction and related costs like Allowance for Funds
20 Used During Construction ("AFUDC") associated with building the proposed new
21 CCGT generator are considerable, as with all large infrastructure investments. The
22 estimated costs are also higher than what was assumed and modeled in the

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1 Company's most recent Interim IRP¹⁰ but are consistent with current industry
2 trends as discussed further by Mr. Long. Mr. Finn discusses economic modeling
3 that was performed that evaluates potential impacts to the Company's existing
4 customers.

5 5. Operational Flexibility – a CCGT generator offers' greater operating flexibility
6 compared to coal and nuclear facilities, though a CCGT generator has certain
7 limitations regarding rapid cycling and load variation.

8 6. Dispatchability – a CCGT generator is dispatchable and able to perform in a
9 baseload or load-following role. As discussed further by Mr. Sharp, other
10 technologies like solar photovoltaic ("PV"), wind, and battery energy storage
11 systems ("BESS") have inherent limitations.

12 7. Site Requirements – optimal siting for a CCGT generator often necessitates access
13 to both a reliable gas supply, suitable water resources, and nearby transmission
14 needed for the interconnection, which may restrict site selection options.

15 8. Maintenance and Reliability – while a CCGT generator is generally highly reliable,
16 the plant equipment demands routine maintenance, which requires careful planning
17 and scheduling to minimize operational disruptions.

18 **Q23: HOW WOULD A UTILITY HISTORICALLY SCOPE OUT A GENERATION**
19 **PROJECT IN ORDER TO PROCEED TO CONSTRUCTION?**

20 **A:** As discussed by Mr. Long, current market conditions are challenging and do not allow for
21 the development methods used in the last 20-plus years that would normally yield firm

¹⁰ See LPSC Docket No. I-36175.

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1 costs and a detailed schedule prior to submitting a certification filing to the LPSC.
2 Historically, a utility would undertake the following steps to develop a firm cost estimate
3 and detailed schedule for a new CCGT generation facility: (1) perform a front-end
4 engineering and design (“FEED”) study followed by (2) a procurement process typically
5 involving multiple requests for proposals (“RFPs”) for major equipment like the turbine
6 OEM and the EPC contractor that (3) would, in turn, provide a high level of design and
7 construction certainty with respect to both cost and schedule prior to submitting a
8 certification filing.

9 **Q24: GIVEN THE CHANGED CIRCUMSTANCES MR. LONG DISCUSSES, WHAT**
10 **STEPS ARE BEING TAKEN BY THE COMPANY TO FURTHER REFINE THE**
11 **COST ESTIMATE AND SCHEDULE FOR THE PROPOSED NEW CCGT**
12 **GENERATOR?**

13 **A:** As I noted above, the Company has retained an industry-leading OE to assist with
14 equipment selection, procurement, vendor negotiations, design, and construction oversight.
15 The Company is also working diligently to complete the power island equipment (“PIE”)
16 selection process and plans to enter into a reservation agreement with the selected turbine
17 OEM (the “Reservation Agreement”) in the next few months, which the Company will
18 provide in this proceeding when it becomes available. Working with its OE, the Company
19 has developed a high-level project schedule, which is attached as Exhibit RB-4 (HSPM).
20 Between now and 2027, the Company plans to begin the EPC selection process, enter into
21 slotting agreements for certain pieces of long lead-time equipment, develop and finalize
22 the facility’s basic design, continue refining the CCGT generator’s estimated cost and
23 schedule, and initiate air permitting.

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1 In the past under a traditional project development process, after selection of the turbine
2 OEM, a process would be initiated to select an EPC contractor. However, circumstances
3 have changed significantly over the last few years, and immediately engaging an EPC
4 contractor to initiate engineering and design and begin procurement is no longer realistic
5 or feasible. Mr. Long discusses the current market environment and the steps the Company
6 is taking to advance the CCGT generator to meet a commercial operation date ("COD") as
7 soon as 2032 to reduce the potential risk of degrading reliability in assets reaching end of
8 life in the mid-2030s.

9 **Q25: WHAT IS THE TYPICAL TIMELINE TO BUILD A NEW CCGT FACILITY?**

10 **A:** The standard timeline from initial conception to the COD has historically been around five
11 (5) years, encompassing both regulatory approvals and construction. However, evolving
12 market dynamics have lengthened the construction period for CCGT projects due to an
13 unprecedented surge in demand for generation capacity, particularly for gas-fired
14 resources. This heightened demand has introduced considerable challenges, including
15 supply chain constraints, extended lead times for critical components, and significant
16 pressure on available resources and labor required to execute these projects. Mr. Long
17 discusses these issues in detail and explains how these challenges are affecting utilities that,
18 like Cleco Power, need to construct new generation to address the risks of an aging
19 generation fleet and meet customer needs.

20 **Q26: HOW DID THE CUSTOMER'S TIMELINE AND SIGNIFICANT LOAD AFFECT**
21 **CLECO POWER'S SELECTION OF A CCGT?**

22 **A:** The Customer's Project timeline and load requirements, by themselves, did not necessitate
23 either the construction of a new generator or Cleco Power's selection of a CCGT resource.

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1 As Mr. Sharp discusses, the Company's long-term resource planning and IRPs have
2 indicated a need for new capacity to address load growth and the expected retirements of
3 several generators in the next 10 years. The combination of the Customer's schedule and
4 evolving market conditions for generation resources has heightened the need to secure
5 Commission approval and to proceed with CCGT construction to timely bring the CCGT
6 generator online. As explained in greater detail by Mr. Sharp, the Company's most recent
7 IRP report¹¹ to the Commission indicates an imminent need for dispatchable generation to
8 address both the Company's aging generation fleet and anticipated load growth. All of that
9 said, matching energy supply with energy consumption is essential. For example, it is
10 necessary to align large-scale, high-load-factor customers such as a data center with
11 comparable high-capacity-factor generators. Generators like a CCGT generator, which can
12 operate in a baseload or load-following role, provide capacity and energy, both of which
13 are necessary for the Company to provide safe, reliable, and affordable electric service to
14 its customers.

15 **IV. PROCUREMENT AND CONTRACTING STRATEGY**

16 **Q27: PLEASE DESCRIBE CLECO POWER'S OVERALL PROCUREMENT AND**
17 **CONTRACTING STRATEGY FOR THE PROJECT.**

18 **A:** As noted above, Cleco Power has retained an OE to assist the Company throughout the
19 development and construction of the proposed new CCGT generator. Cleco Power is
20 currently in the process of selecting a turbine OEM and is evaluating key technical and
21 commercial factors, including efficiency, performance, delivery schedule, proposed

¹¹ See LPSC Docket No. I-37725 (the "Interim IRP").

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1 commercial terms, industry experience with the proposed equipment, and pricing. The
2 Company expects to select a turbine OEM and execute a Reservation Agreement in the
3 next few months and will provide the Reservation Agreement in this proceeding once it is
4 available.

5 Early in 2027, Cleco Power will begin evaluating potential EPC contractors. Given the
6 overall CCGT generator development timeline and anticipated turbine delivery date, it is
7 not feasible to begin the EPC contractor selection process before that time. Unlike a
8 traditional EPC selection process that likely would rely heavily on fixed pricing, Cleco
9 Power expects its evaluation to place greater emphasis on commercial terms that address
10 current market constraints. These terms may include when and how an EPC contractor can
11 provide greater price certainty, what assurances the contractor can offer regarding schedule
12 and execution, what incentives may help secure reasonable and more certain pricing, and
13 how the Company can manage cost categories that must remain variable. The specific
14 treatment of variable price components will be addressed during EPC contractor
15 negotiations.

16 **Q28: HAS CLECO POWER TESTED POTENTIAL MARKET INTEREST IN THIS EPC**
17 **CONTRACTING APPROACH?**

18 **A:** Yes. Cleco Power has excellent relations with all three major turbine OEMs, multiple top-
19 tier EPC contractors, and many of the top-tier engineering and design companies. The
20 Company has been in communication with many of these companies over the past year and
21 has received consistent support. In early 2027, Cleco Power plans to utilize a request for
22 information ("RFI") process to evaluate market interest in an EPC structure incorporating

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1 the PIE assignment. The planned RFI process will indicate if sufficient interest exists from
2 major EPC contractors for the contracting approach that I described above.

3 **Q29: WHAT KEY COMMERCIAL TERMS AND LIMITATIONS DOES CLECO**
4 **POWER ENVISION EXISTING UNDER THE EPC STRUCTURE THAT IS**
5 **BEING CONTEMPLATED?**

6 **A:** Cleco Power plans to utilize a modified EPC contract process based on an open
7 book/closed book structure with certain variable price categories, such as labor attraction,
8 transportation, and tariffs. Further, Cleco Power plans to assign the PIE agreement to the
9 EPC contractor to manage and integrate the PIE agreement into the total work plan (the
10 "Assignment Agreement"). The Assignment Agreement contemplated by the Company
11 will include several important commercial conditions and limitations as follows:

- 12 • The EPC contractor will typically charge a material fee associated with the
13 assignment of the PIE agreements, which reflects the obligations and risks assumed
14 by the contractor.
- 15 • The EPC contractor will be expected to pass through OEM guarantees and
16 warranties on a back-to-back basis. Unlike historical market conditions, Cleco
17 Power does not expect an EPC contractor to provide guarantees that exceed the
18 OEM level.

19 **Q30: CAN YOU PROVIDE EXAMPLES OF HOW RISK MIGHT BE ALLOCATED**
20 **UNDER THIS ASSIGNMENT AGREEMENT STRUCTURE?**

21 **A:** Yes. Several examples below illustrate how risk might be allocated (actual terms may vary
22 based on negotiations):

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- 1 • Under an Assignment Agreement, the entire PIE agreement will be assigned to the EPC
- 2 contractor to manage, transferring most of the rights and obligations to the EPC
- 3 contractor. Certain rights and obligations will be shared while others will be retained
- 4 by Cleco Power. The assignment, sharing, and retaining of rights and obligations will
- 5 be negotiated as a matter of course during contracting.
- 6 • In large part, the OEM and the EPC contractor will maintain their respective risk
- 7 profiles, as the EPC contractor is simply passing through any guarantees.
- 8 • As an example, if the OEM agreements include limitations on technical advisory
- 9 ("TA") hours, any cost overruns related to additional OEM support could be passed
- 10 through to Cleco Power.
- 11 • Performance guarantees for core equipment are expected to remain with the OEM,
- 12 while the EPC contractor will provide guarantees relating to auxiliary load and certain
- 13 balance-of-plant systems.

14 **Q31: WILL THE EPC CONTRACT BE FIXED PRICE?**

15 **A:** No. Although the CCGT generator project will be structured under an EPC framework,

16 Cleco Power plans, due to prevailing market conditions, to use an open book-to-closed

17 book pricing model. Certain costs will be finalized after EPC contract execution; however,

18 there is risk associated with escalation between now and when pricing is finalized.

19 **Q32: WHAT COST RISKS MAY REMAIN EVEN AFTER PRICING IS FINALIZED?**

20 **A:** Even after pricing is established, certain cost elements are expected to remain variable or

21 subject to adjustment. These cost elements may include labor market conditions, logistics

22 and transportation costs, and other market-driven inputs. In some cases, these costs may

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1 be addressed through contractual allowances; however, such mechanisms do not fully
2 eliminate the risk of cost escalation.

3 **Q33: GIVEN THESE LIMITATIONS, WHAT ARE THE BENEFITS OF AN EPC**
4 **DELIVERY MODEL?**

5 **A:** Despite these limitations, an EPC delivery model provides several important advantages:

- 6 • It will centralize responsibility for staffing, coordination, integration, and project
7 execution within a single experienced entity.
- 8 • EPC contractors with historically significant project risk exposure are often well-
9 equipped to manage schedules, control costs, and attract required skilled labor.
- 10 • EPC contractors typically utilize sophisticated project management systems and
11 tools that enhance both project execution and oversight.

12 **Q34: WHAT ARE THE KEY MILESTONES IN THE PROJECT'S SCHEDULE?**

13 **A:** I described above the actions the Company is taking during the remainder of 2026 and
14 early 2027 while the Commission is considering this Application. For a high-level project
15 schedule, please see Exhibit RB-4 (HSPM).

16 **Q35: HOW DOES CLECO POWER PLAN TO SELECT A TURBINE OEM?**

17 **A:** The initial turbine OEM selection will focus primarily on anticipated delivery date, price,
18 and the commercial terms of the Reservation Agreement. Because the final terms of the
19 equipment supply agreement will not be known before the Reservation Agreement is
20 executed, Cleco Power is evaluating the available information at this stage, including
21 anticipated delivery date, reservation terms, cancellation rights, payment schedules, cost
22 certainty, and expected equipment performance.

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Q36: HOW WILL CLECO POWER MANAGE CONSTRUCTION OF THE CCGT GENERATOR?

A: Cleco Power has retained an experienced and trusted OE to support the Company throughout the development, construction planning, and construction management phases of the project. Integrating an outside resource and its best practices with Cleco Power's internal project management and controls and processes will help ensure proper oversight. Cleco Power's "playbook" for constructing large capital projects is well-established; however, the size of the investment needed to construct the proposed CCGT facility coupled with the timeline and unprecedented supply chain issues warrant an enhanced process. As I noted earlier, Mr. Long addresses the current state of the market and the challenges utilities like Cleco Power and merchant developers are facing while trying to procure equipment and construct new generation resources.

Q37: DO YOU ANTICIPATE ANY SITE CONDITION ISSUES THAT COULD CAUSE DELAYS?

A: No. The selected site for the proposed CCGT facility is well positioned near three transportation modes, several natural gas supply pipelines, and the Company's transmission system, which should support efficient equipment delivery and project development. Although the site is located within a 100-year floodplain, Cleco Power expects to complete necessary site upgrades well in advance of full EPC mobilization, so those upgrades do not affect the construction schedule.

Q38: WHAT IS THE EXPECTED COST TO BUILD THE NEW CCGT FACILITY?

A: The current cost estimate is [REDACTED], which reflects a Class 4 overnight estimate. It does not include any contingency, estimated escalation, AFUDC, nor any potential

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transmission upgrades discussed by Mr. Thibodeaux that MISO may identify as being necessary for the CCGT generator to utilize network transmission service. A high-level breakdown of the estimated costs is provided in Table 2 (HSPM).

Table 2 (HSPM). Breakdown of Estimated Overnight Costs.

Component	Estimated Costs (\$M)
Power Island Equipment	
Balance of Plant/EPC Equipment Procurement	
EPC Construction Costs	
Owners Costs (including Taxes and Tariffs)	
Natural Gas Pipeline	
Total¹²	

Q39: HOW DID CLECO POWER DEVELOP THE OVERNIGHT COST ESTIMATE?

A: The Company worked with its OE to develop the Class 4 overnight cost estimate detailed in Table 2 (HSPM). The Company is estimating contingency at [REDACTED], which reflects the nature of a Class 4-level cost estimate. The cost estimate will become more certain once the Company selects an EPC contractor and the scope of work, design, and engineering for the CCGT generator is further refined. However, a firm cost estimate consistent with what the Commission has typically seen in prior certification proceedings is not expected to be available until the 2030 timeframe. As discussed in further detail by Mr. Long, due to high industry demand for power generation major equipment, production queues for turbines and generator equipment have extended delivery times (to what is currently estimated to be around 48 months). As such, the turbine supplier OEMs will

¹² The total overnight cost estimate in Table 2 (HSPM) does not include any contingency, estimated escalation, or AFUDC. It also does not include an estimated [REDACTED] for the CCGT generator substation, which is discussed by Mr. Thibodeaux in his direct testimony.

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1 begin detailed engineering for the turbine generator equipment in or around 2029, which
2 will provide essential design details and data that will be required to initiate the more
3 detailed engineering design by the EPC contractor. That process will produce a more
4 defined scope, setting the timeframe for the plant coming online as early as 2032. Mr.
5 Long further discusses the current challenges faced by the industry.

6 **Q40: DOES CLECO POWER HAVE SUFFICIENT DESIGN INFORMATION TODAY**
7 **TO DEVELOP A FIRM TOTAL COST ESTIMATE COVERING THE CCGT**
8 **GENERATOR REACHING COD?**

9 **A:** No. As I noted, the cost estimate in Table 2 (HSPM) represents overnight values and does
10 not include any contingency, AFUDC, or expected escalation of labor, commodity, and
11 other costs. And as explained by Mr. Long in his testimony, Cleco Power's position is
12 typical of current industry conditions due to extended project development timelines and
13 supply chain constraints.

14 **Q41: DOES THE COST ESTIMATE IN TABLE 2 REFLECT COST ESCALATION**
15 **ADJUSTMENTS AND CONTINGENCIES?**

16 **A:** No. The overnight cost estimate in Table 2 (HSPM) does not include any contingency, nor
17 does it include any escalation that may occur between now and the expected COD. It also
18 does not include AFUDC or any costs that MISO may identify as part of the ERAS study
19 process, which Mr. Thibodeaux addresses in his direct testimony.

20 **Q42: DO YOU BELIEVE THE OVERNIGHT COST ESTIMATE IS REASONABLE?**

21 **A:** Yes. As I noted, the Company worked with its OE, which is well respected in the industry
22 and is assisting other clients with similar projects, either as OE or in support of an EPC
23 contractor.

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Q43: ARE YOU CONFIDENT THAT THE OVERNIGHT COST ESTIMATE IS REASONABLE COMPARED WITH THE CURRENT MARKET FOR SIMILAR PROJECTS?

A: Yes. The estimate is based on the best available information and is consistent with what the OE has communicated to the Company based on their experience in the current market. I would reiterate that Mr. Long addresses the current market dynamics and the level of uncertainty that is affecting natural gas-fired projects that are under development right now.

Q44: HOW IS THE COMPANY ADDRESSING POTENTIAL COST ESCALATION?

A: The Company developed an escalation factor to apply to the overnight cost estimate using data provided by [REDACTED].

Q45: PLEASE DISCUSS THE DIFFERENCE BETWEEN CONTINGENCY AND ESCALATION?

A: The Company estimates up to [REDACTED] for contingency, which is consistent with a Class 4 cost estimate. Contingency addresses uncertainty and the risk of an unforeseen event (or series of events) that may affect major equipment costs and/or the construction timeline, which in turn can increase labor costs and AFUDC. Examples of unanticipated costs that can affect a project with a lengthy construction timeline include unexpected tariffs or unforeseen market disruption, such as is being caused by the ongoing conflict and developments in the Middle East.

In contrast, escalation is intended to address anticipated increases in key inputs including labor costs, manufactured equipment, and commodity prices (*e.g.*, steel, concrete). Assuming Commission approval is granted in early 2027 for the Company to move forward with its proposed CCGT generator, when construction begins, prices will likely be higher

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1 than they are today for key inputs; the use of escalation is meant to adjust the overnight
2 cost and anticipated annual spend values for inflation. As I noted earlier, key equipment
3 suppliers like the turbine OEM that the Company plans to select in the coming months can
4 provide indicative prices but are unwilling to guarantee prices for future delivery given that
5 those suppliers are subject to the same escalation in future costs.

6 **Q46: HAS THE COMPANY PREPARED AN ESTIMATE OF AFUDC AND THE TOTAL**
7 **FINAL COST OF THE CCGT GENERATOR?**

8 **A:** Yes. [REDACTED]

9 [REDACTED]
10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]

14 **Q47: PLEASE DESCRIBE AVAILABLE NATURAL GAS SUPPLY IN THE VICINITY**
15 **OF THE NEW CCGT GENERATOR'S LOCATION.**

16 **A:** [REDACTED]

17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED]
21 [REDACTED]

22 **Q48: PLEASE DESCRIBE HOW MUCH NATURAL GAS THE PROPOSED CCGT**
23 **GENERATOR WILL REQUIRE.**

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1 **A:** The proposed CCGT generator will have a nameplate capacity of 756 MW and will operate
2 primarily as a baseload unit with a base production of [REDACTED] and the ability to duct fire
3 for a total peak production of 756 MW. The unit's peak daily fuel requirement is estimated
4 at approximately [REDACTED] which includes supplemental duct firing.
5 Assuming a standard planned maintenance schedule that includes approximately 30 days
6 of outage annually, the unit's maximum annual natural gas consumption is projected to be
7 approximately [REDACTED].

8 **Q49: WHAT STEPS WILL CLECO POWER TAKE TO DEVELOP A NATURAL GAS**
9 **SUPPLY PLAN FOR THE CCGT GENERATOR?**

10 **A:** Cleco Power's overall fuel supply strategy is designed to ensure deliverability to the
11 Company's fleet of generators across a range of market and operating conditions. For gas-
12 fired units, existing pipeline interconnections provide access to multiple supply basins and
13 market hubs; the ability to access underground salt-dome gas storage helps mitigate
14 disruptions and balance the Company's day-to-day needs.

15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED]
21 [REDACTED]
22 [REDACTED]
23 [REDACTED]

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1 [REDACTED]
2 [REDACTED]
3 [REDACTED]

4 **Q50: IS THE DELIVERED COST OF NATURAL GAS TO THE CCGT GENERATOR**
5 **EXPECTED TO BE COMPARABLE TO HENRY HUB PRICING?**

6 **A:** Yes. The proposed CCGT generator's location is expected to provide Cleco Power with
7 access to natural gas supply points with a high correlation to Henry Hub spot market prices,
8 and at times supply may be available at a discount to Henry Hub. Further, the Company
9 expects the delivered cost of natural gas to the CCGT generator to be generally comparable
10 to Henry Hub pricing for delivered natural gas supply after accounting for both commodity
11 basis and transportation charges. Actual delivered costs will depend on prevailing market
12 conditions, available pipeline capacity, contractual transportation arrangements, and the
13 specific supply points ultimately used to serve the CCGT generator.

14 **Q51: DOES THE COMPANY ANTICIPATE HAVING TO MAKE ANY NATURAL GAS**
15 **INFRASTRUCTURE INVESTMENTS TO ACCESS SUPPLY?**

16 **A:** [REDACTED]
17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED]
21 [REDACTED]
22 [REDACTED]
23 [REDACTED]

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1 [REDACTED]
2 [REDACTED]
3 [REDACTED]
4 [REDACTED]

5 **Q52: HAS THE COMPANY PREPARED A COST ESTIMATE IF IT BECOMES**
6 **NECESSARY TO CONSTRUCT GAS INTERCONNECTION FACILITIES THAT**
7 **CLECO POWER WILL OWN AND MAINTAIN?**

8 **A:** The Company has not prepared a detailed cost estimate given the stage of project
9 development and the possibility that the gas supply infrastructure could be owned and
10 operated by another party. However, to develop a revenue requirement for modeling
11 purposes, the Company estimates the cost at [REDACTED] (overnight cost basis).

12 **Q53: YOU MENTIONED THE BRAME ENERGY CENTER. ARE THERE ANY**
13 **OPERATIONAL INTERDEPENDENCIES AND/OR SYNERGIES WITH GAS**
14 **SUPPLY TO THE PROPOSED CCGT GENERATOR?**

15 **A:** No, there are no operational interdependencies that I am aware of. As far as possible
16 synergies, the new natural gas supply arrangements discussed above needed for the CCGT
17 generator may provide incremental supplier diversification as well as the flexibility of
18 having new supply available for the nearby Brame Energy Center. As I discussed earlier,
19 the Company and the other two entities that comprise the Joint Owners are considering the
20 possibility of converting the Rodemacher 2 unit to burn natural gas, in which case
21 additional, to-be-determined gas supply synergies may be achieved.

22 **Q54: HAS CLECO POWER DEVELOPED ESTIMATES FOR O&M COSTS THAT**
23 **WILL BE INCURRED RELATED TO THE CCGT FACILITIES?**

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A: Yes. Estimates for O&M costs have been developed using a combination of Company experience at the Coughlin and Acadia plants and industry data for new CCGT facilities provided by the OE.

Q55: HOW DID CLECO POWER DEVELOP THE ESTIMATED O&M COSTS?

A: Cleco Power developed the O&M cost estimates for the CCGT unit based on operating experience and work with the Company's OE. For payroll costs, Cleco Power estimates a plant staff of approximately 35 full-time equivalent employees ("FTEs"), which includes FTEs from key support organizations to provide services to the plant for safety, environmental, compliance, technical support, maintenance planning, outage planning and execution. Routine O&M and maintenance costs have been estimated based on experience at the Company's existing CCGT facilities, Acadia and Coughlin. The estimated Long-Term Service Agreement ("LTSA") costs for gas turbine major maintenance expenses are estimated using information from combustion turbine OEMs that was provided in conjunction with the ongoing process the Company is using to select a turbine OEM.

Table 3 (HSPM). Estimated CCGT First-Year O&M Expenses (\$ millions, 2034 Cost Basis).

Expense Type	Estimated Cost
Wages, Salaries & Benefits	
Fixed O&M Expenses	
Variable O&M Expenses	
LTSA Variable Expense (recovered through fuel adjustment)	
Total Expenditures	

¹³ Depending on the selected turbine OEM, the Company may incur an additional one-time fee. The current cost estimate is indicative of expected LTSA variable fees during the first year of commercial operation.

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Q56: HOW WERE PAYROLL COST ESTIMATES DETERMINED?

A: Payroll costs were determined using an estimated staffing model for a stand-alone single CCGT facility based on Cleco Power's operational experience along with allowance for additional personnel for key support roles, including outage planning, water chemistry, plant-level project management, safety, environmental, and other miscellaneous support functions. Costs were developed using Cleco Power's current compensation rates for these positions, with escalation applied to determine an escalated cost basis tied to when the CCGT generator is expected to come online. Cleco Power estimates that the CCGT plant will be staffed with approximately 27 on-site FTEs, with eight (8) additional FTEs for key support functions, which may be a combination of some full-time and some partial allocation of shared corporate support roles. Note that some of these positions may not be incremental costs to the Company as other units at Brame Energy Center may transition to support the new CCGT unit as other units retire in the mid-2030s.

Q57: WHAT O&M OUTAGE EXPENSES WERE INCLUDED?

A: Cleco Power expects the major maintenance on the combustion turbine will be performed under an LTSA with the turbine OEM. Those estimated costs are reflected separately above in Table 3 (HSPM). Other outage expenses, including routine annual outage expenses and steam turbine maintenance and inspections, are not expected to be incurred in the first year of commercial operation but will be incurred in subsequent years afterward.

Q58. WHAT TYPES OF COSTS ARE INCLUDED IN THE FIXED O&M EXPENSES?

A: Fixed O&M expenses include the costs for performing minor maintenance on the plant facilities (both preventive and corrective maintenance); infrastructure management for buildings, structures, and grounds; administrative costs; plant chemicals not related to

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1 emissions control; and other miscellaneous costs for safety, environmental, and regulatory
2 compliance

3 **Q59: PLEASE DESCRIBE WHAT IS INCLUDED IN THE VARIABLE O&M COSTS**
4 **THAT ARE SEPARATE AND APART FROM THE LTSA.**

5 **A:** Variable O&M Costs for the first year of operation include chemicals and reagents such as
6 ammonia to control emissions of NO_x within environmental permit limits for the plant.

7 **Q60: HOW DOES CLECO POWER PLAN TO MANAGE LONG-TERM MAJOR**
8 **MAINTENANCE?**

9 **A:** As I noted, Cleco Power expects to manage long-term major maintenance for the CCGT
10 generator by executing an LTSA with the OEM of the turbine generator equipment. Exact
11 terms and pricing will be dependent on the final selection of the turbine OEM, but the
12 general concepts and costs of an LTSA are similar among the major OEMs. I would add
13 that the Company has existing LTSAs in place for its Acadia and Coughlin CCGT units.

14 A gas turbine LTSA is a multi-year contract—often structured around major inspection
15 intervals up to approximately 15-17 years—that defines how the OEM delivers
16 maintenance, parts, and performance support for the turbine and associated equipment.
17 Typical scope includes planned maintenance outages (combustor, hot gas path, and major
18 inspections), supply and refurbishment or replacement of covered parts, repair services,
19 field labor, and coverage for unplanned events such as collateral damage repair, with
20 clearly defined “covered” versus “non-covered” components and responsibilities. The
21 scope of the LTSA is expected to bundle parts, labor, repairs, and performance guarantees,
22 and risk-sharing mechanisms (availability, reliability, or outage duration guarantees) and
23 pricing tied to fired hours, starts, and/or milestone events.

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1 The term of the LTSA is expected to include coverage through the second major inspection
2 outage of the combustion turbine, or approximately 120,000 to 135,000 service hours with
3 an upper time cap, aligning contractor obligations with turbine lifecycle exposure.
4 Ancillary services under the LTSA are expected to include outage planning and program
5 management, digital monitoring and diagnostics, inventory and parts pool management,
6 engineering support, upgrade/retrofit options, and could include major component
7 exchange programs (e.g., rotor or valve swap-outs) designed to reduce outage duration and
8 operational risk, ultimately providing predictable maintenance costs and improved
9 reliability over the asset life.

10 The cost of the LTSA varies by provider, but Cleco Power projects that the total cost over
11 the term of the LTSA will be in the range of [REDACTED]. For the first year of the
12 LTSA, the Company estimates that the cost will be [REDACTED] but could be higher
13 depending on the turbine OEM selected if there are additional one-time fees incurred when
14 the LTSA is initiated to cover the initial supply of spare parts for the combustion turbine.
15 The LTSA fees are expected to escalate over the term of the contract, which will be based
16 on an agreed-upon cost index. The Company anticipates executing an LTSA with the
17 selected turbine OEM at or near the time it executes the power island supply contract in
18 2027. Company witnesses Ms. McDowell and Mr. Owens address cost recovery of the
19 LTSA in their respective testimonies.

20 **Q61: WHAT PERMITS WILL BE REQUIRED BEFORE THE COMPANY CAN BEGIN**
21 **CONSTRUCTION ON THE PROPOSED CCGT GENERATOR?**

22 **A.** As I noted above, by virtue of burning natural gas, the CCGT generator will have air
23 emissions of criteria pollutants like NO_x and sulfur dioxide ("SO₂"). The proposed CCGT

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1 generator will require a construction permit and an operating permit from the LDEQ under
2 applicable federal and state environmental rules. The CCGT generator will be state-of-the-
3 art as far as its efficiency and operations and the Company will demonstrate that the
4 generator meets all applicable air emission standards. Based on the current project
5 timeline, the Company estimates that it will submit the application for the air permit to the
6 LDEQ in 2027, which is well before construction is expected to begin.

7 The Company plans to use a combination of surface water and groundwater to meet the
8 needs of the steam generator and cooling processes. Groundwater wells will be permitted
9 by the Louisiana Department of Conservation and Energy. Surface water withdrawal and
10 discharge of all industrial wastewater will be permitted through the Louisiana Pollution
11 Discharge Elimination System ("LPDES") and regulated by the LDEQ. Although the
12 Company is not required by state or federal regulations to acquire the water-related permits
13 prior to commencement of construction, Cleco Power intends to have these permitting
14 processes in motion before breaking ground.

15 An LPDES General Construction Permit and a construction Stormwater Pollution
16 Prevention Plan ("SWPPP") will also need to be in place. Finally, a United State Army
17 Corps of Engineers ("USACE") general permit, also referred to as a Nationwide Permit, is
18 expected to be required prior to construction of the planned access roads.

19 **V. CONSTRUCTION RISK MITIGATION**

20 **Q62: WHY IS IT IMPORTANT TO HAVE PLANS IN PLACE TO MANAGE AND**
21 **MITIGATE THE POTENTIAL RISKS ASSOCIATED WITH CONSTRUCTING**
22 **THE PROPOSED NEW CCGT GENERATOR?**

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1 **A:** The proposed new CCGT generator represents a substantial capital investment and must
2 be carefully managed. Management oversight includes consideration of the risks that can
3 be reasonably foreseen and the development of a plan to manage and mitigate those risks.
4 Effective project management does not seek to eliminate all potential risks irrespective of
5 costs. Instead, effective project management should reasonably manage risks considering
6 the probability of occurrence, potential magnitude of impact, and cost to mitigate.

7 **Q63: WHAT IS CLECO POWER'S PLAN TO MITIGATE RISKS AFFECTING THE**
8 **CCGT PROJECT'S SCHEDULE AND ESTIMATED COSTS?**

9 **A:** As I discussed earlier, the Company has retained an OE. The Company will continue to
10 work with its OE to select its turbine OEM, which is expected to occur in the coming
11 months and will involve the execution of a Reservation Agreement. The Reservation
12 Agreement will confirm the Company's place in the OEM's manufacturing queue and will
13 help ensure the project schedule is attainable. I outlined above the Company's plan to
14 engage with EPC contractors in early 2027, after which the detailed scoping, design, and
15 engineering can begin in earnest. In turn, completion of that phase of work will allow the
16 Company to engage with and select other key vendors, such as the manufacturer of the heat
17 recovery steam generator and other key equipment suppliers. As Mr. Long discusses in his
18 testimony, the phased approach the Company plans to use will allow for more refined
19 project costs and a firmer schedule as the process progresses towards the start of
20 construction.

21 **Q64: COULD COSTS ESCALATE BEYOND THE TOTAL COST ESTIMATE YOU**
22 **PROVIDED?**

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1 **A:** Yes, that is possible. I describe below a quarterly monitoring plan that the Company
2 proposes to initiate in mid-2027, assuming Commission approval. As part of that quarterly
3 monitoring report, the Company will discuss any factors that may affect the CCGT
4 generator's final cost and/or schedule along with related matters. As such, the Commission
5 and any other parties to this proceeding will have full transparency into any circumstances
6 that may adversely affect the final cost and/or schedule as well as what steps the Company
7 is taking to mitigate any adverse developments. In the event the final costs to construct the
8 CCGT generator exceed the costs the Company is seeking certification for in this
9 proceeding, the Commission will ultimately determine whether they were prudently
10 incurred and any follow-up course of action.

11 **Q65: WHAT TYPES OF INSURANCE ARE INCLUDED IN THE COST ESTIMATES**
12 **FOR THE PROPOSED NEW CCGT AND WHAT IS COVERED?**

13 **A:** The cost estimate for the proposed CCGT generator includes provisions for insurance
14 coverage consistent with industry standards for utility-scale generation construction
15 projects of comparable size and complexity. The primary component of these costs is
16 Builder's Risk insurance (also referred to as Course of Construction insurance), which is
17 expected to total approximately [REDACTED] for the duration of the construction period.
18 This estimated amount is already reflected in the overnight cost estimate provided in Table
19 2 (HSPM) above.

20 Builder's Risk insurance is designed to provide "all-risk" coverage, subject to standard
21 policy exclusions and conditions, for physical loss or damage to the project during
22 construction and commissioning. Covered property typically includes major equipment,
23 materials and installed works, encompassing key plant components such as gas turbine

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1 generators, steam turbine generators, heat recovery steam generators, main transformers,
2 and balance of plant systems.

3 **VI. MONITORING AND REPORTING**

4 **Q66: PLEASE DESCRIBE THE COMPANY'S PROPOSED QUARTERLY**
5 **MONITORING PLAN.**

6 **A:** Beginning on or about August 31, 2027, assuming the Commission approves this
7 Application at its March 2027 Business and Executive meeting, the Company proposes to
8 submit a quarterly monitoring report to the Commission. Thereafter and until the
9 completion of the proposed new generator, Cleco Power would submit its quarterly
10 monitoring report on or about February 28, May 31, August 31, and November 30. Each
11 quarterly monitoring report will cover the status of construction progress on the CCGT
12 generator and transmission infrastructure for the prior calendar quarter, and will address
13 schedule, costs, material issues related to key vendors (if any), safety matters, the status of
14 environmental and other necessary permits, and any other matters that the Company needs
15 to bring to the Commission's attention.

16 **Q67. IS THE COMPANY PROPOSING ANY OTHER PERIODIC REPORTING?**

17 **A.** Yes. Mr. Finn discusses a proposed report that would be submitted to the Commission
18 annually, which would cover various matters related to the Customer's data center.

19 **VII. CONCLUSION**

20 **Q68: PLEASE SUMMARIZE YOUR TESTIMONY.**

21 **A:** My testimony supports Cleco Power's request to construct a new 756 MW natural gas-
22 fired CCGT generator to serve the Company's capacity and energy needs while preserving
23 reliable service for all customers. Cleco Power's existing generation fleet has been well-

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1 maintained and continues to provide reliable service, but a significant portion of that fleet
2 is aging, faces increasing environmental compliance requirements, and is expected to
3 require retirement, repowering, or significant investment over the next decade. At the same
4 time, Cleco Power is preparing to serve new load from the Customer's hyperscale data
5 center, which is expected to require up to 430 MW of reliable power and to increase Cleco
6 Power's peak demand and annual energy requirements. The combination the Company's
7 aging generation resources, existing customer load and anticipated growth, the need to
8 satisfy capacity obligations, and the long development timelines for new generation make
9 it necessary for Cleco Power to move forward now with new dispatchable generation.

10 The proposed CCGT generator is the appropriate resource because it is dispatchable,
11 efficient, and capable of operating in a baseload or load-following role, allowing Cleco
12 Power to match reliable supply with the ongoing needs of its customers. The unit will also
13 support system reliability in Central Louisiana, provide accredited capacity needed to meet
14 planning reserve requirements, and replace or supplement capacity that may otherwise be
15 lost as older units reach the end of their useful lives or become subject to more restrictive
16 operating requirements. Although current market conditions create challenges related to
17 equipment availability, cost certainty, construction timelines, and labor and supply chain
18 issues, Cleco Power has taken prudent steps to advance the CCGT generator project,
19 including retaining an OE, moving forward with turbine OEM selection, developing a
20 procurement and contracting strategy, evaluating natural gas supply options, and proposing
21 ongoing Commission monitoring and reporting. Timely approval is essential because
22 delays would increase the risk that needed generation cannot be placed in service before
23 existing resources become unavailable or insufficient, exposing customers to reliability

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1 risks, higher capacity purchase costs, and potential inability to meet capacity obligations
2 in the coming years.

3 **Q69: WHAT WOULD BE THE CONSEQUENCES IF CLECO POWER IS UNABLE TO**
4 **TIMELY SECURE AUTHORIZATION TO CONSTRUCT THE REQUESTED**
5 **GENERATION RESOURCE?**

6 **A:** As Company witness Mr. Long explains in more detail, development timelines for new
7 generation projects are now historically long because of high demand, extended order
8 cycles for major generation equipment, labor constraints, and other industry-wide supply
9 limitations. Cleco Power also has aging generating assets, including Nesbitt 1 and
10 Rodemacher 2, that have served customers well and remained fit for service throughout
11 their operating lives. However, those units are expected to reach the end of their useful
12 lives and require replacement by 2035.

13 For that reason, it is imperative that Cleco Power begin the replacement process now.
14 Current project development timelines are now longer, and the Company must act promptly
15 to ensure that new, reliable, fuel-efficient generation capable of serving baseload needs is
16 available before those existing units are no longer fit for service. If Cleco Power cannot
17 timely secure authorization to construct the proposed CCGT generator, the Company and
18 its customers will face increasing risk that replacement generation will not be online when
19 needed. That outcome could expose customers to significant risks, including expensive
20 capacity purchases, and could impair Cleco Power's ability to satisfy the LPSC's
21 requirements to have sufficient capacity available to reliably serve customer load while
22 also meeting its reserve margin and other MISO-imposed requirements.

23 **Q70: DOES THIS CONCLUDE YOUR TESTIMONY?**

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1 **A:** Yes, at this time.

STATE OF LOUISIANA

PARISH OF RAPIDES

AFFIDAVIT

BE IT KNOWN, that before me, the undersigned Notary Public, duly commissioned and qualified for the state and parish/county aforesaid, personally came and appeared:

ROBERT BREEDLOVE

("Affiant"), who after being duly sworn did depose and say:

1. Affiant has prepared Direct Testimony on behalf of Cleco Power LLC in support of the Application of Cleco Power LLC for Authorization of: (I) Site Specific Contract for Large Load Customer; (II) Bridge Capacity Contract; (III) Construction of New Transmission Interconnection; (IV) Construction of New Generation; (V) Associated Waivers; and (VI) Expedited Treatment.

2. To the best of Affiant's knowledge, information, and belief, Affiant's Direct Testimony is true, accurate, and complete in all material respects as of the date of this Affidavit.



Robert Breedlove
Cleco Corporate Holdings LLC
2030 Donahue Ferry Road
Pineville, LA 71360

SWORN TO AND SUBSCRIBED
BEFORE ME, NOTARY PUBLIC,
THIS 29th DAY OF JUNE 2026.



NOTARY PUBLIC

BAR ROLL/NOTARY ID NO.: 51231

MY COMMISSION EXPIRES: at death



EXHIBIT RB-1

USEFUL LIFE ASSESSMENT REPORT

REDACTED TO OMIT CONFIDENTIAL,
COMPETITIVELY SENSITIVE, TRADE SECRET,
AND PROPRIETARY INFORMATION PURSUANT
TO RULE 12.1 OF THE COMMISSION'S
RULES OF PRACTICE AND PROCEDURE

EXHIBIT RB-2

CLECO POWER LETTER TO LDEQ REGARDING RODEMACHER 2



2030 Donahue Ferry Rd
P. O. Box 5000
Pineville, LA 71361-5000
318 484-7718

March 2, 2026

Jenniffer Sheppard
Administrator, Water Permits Division
Louisiana Department of Environmental Quality
Galvez Building, 602 North Fifth Street
Baton Rouge, LA 70802

RE: Initial Request Letter Pursuant to 40 C.F.R § 423.19(q) Requesting Site-Specific ELG Deadlines – Brame Energy Center, Rodemacher Unit 2 (LPDES Permit LA0008036; AI No. 2922)

Ms. Sheppard:

I. Introduction

Cleco Power LLC ("Cleco") respectfully submits this initial request letter pursuant to 40 C.F.R. § 423.19(q) to request site-specific extensions under 40 C.F.R. § 423.18(d) for two deadlines applicable to Brame Energy Center's Rodemacher Unit 2 under federal effluent limitations guidelines ("ELG") regulations. Specifically, Cleco, the permittee for LPDES Permit LA0008036, and the joint owners¹ of Rodemacher Unit 2 ("Owners") seek: (1) an extension of the December 31, 2025 deadline to transfer out of the 2028 ELG coal cessation subcategory, pursuant to 40 C.F.R. § 423.18(d)(2); and (2) an extension of the December 31, 2025 deadline to comply with the generally applicable bottom ash transport water ("BATW") limitation to limit discharges to 10% of the bottom ash system volume, pursuant to 40 C.F.R. § 423.18(d)(1).

Rodemacher Unit 2 ("Rodemacher 2" or the "Facility") remains a critical asset in Louisiana's power generation portfolio, and the Owners are committed to coordinating with LDEQ, the Louisiana Public Service Commission, the LEPA Board of Directors, and the Lafayette City Council to ensure regulatory alignment, preserve operational flexibility, and provide compliant, cost-effective service for the remainder of the unit's operating life while remaining compliant with ELG regulations. The Owners have not finally determined that they will continue combusting coal at Rodemacher 2 beyond 2028 but are filing this request to preserve operational flexibility. In the meantime, the Owners are undertaking ongoing work towards both potential compliance paths: (a) ceasing coal combustion and converting to natural gas operation by the end of 2028, and alternatively, (b) continuing coal combustion beyond 2028, in which case the two extensions requested in this letter are necessary for continued operations of Rodemacher 2.

¹ The joint owners of Rodemacher Unit 2 are Cleco, Lafayette Public Power Authority ("LPPA"), and Louisiana Energy & Power Authority ("LEPA").

II. Letter Requirements and Contents

This letter summarizes the site and unit background (Section III), the relevant ELG regulatory background (Section IV), the current ELG compliance path the Facility is working towards (Section V), the proposed alternative compliance path requiring the extensions requested in this letter (Section VI), the regulatory basis for the requested deadline extensions (Section VII), the circumstances warranting extension (Section VIII), and a proposed compliance schedule (Section IX).

Accordingly, this letter complies with the requirements of 40 C.F.R. § 423.19(q)(2) for an initial extension request letter:

- “Detail the significant unexpected circumstance in § 423.18(d)(2) and a compelling narrative that explains why these unexpected circumstances warrant an alternative applicability date by the permitting authority in light of the Facility’s plans and execution of those plans” – **Sections VI and VIII.**
- “Contain a proposed schedule of compliance to be incorporated into the permit, supported by detailed engineering dependency chart that clearly shows the milestones leading to compliance as soon as possible given the unexpected circumstances described in the letter, including contingencies for critical path steps.” – **Section IX and Exhibit A.**
- “In the case of a missed notice of planned participation, annual progress report, or other reporting or recordkeeping requirement that should have been submitted prior to March 2, 2026, the letter must also attach such reporting requirements.” – **No missed reporting requirement identified.**

In accordance with 40 C.F.R. § 423.19(q)(5), the Facility is submitting a single initial request letter for both requested extensions to the December 31, 2025, deadlines for (1) transfer out of the 2028 NOPP subcategory and (2) BATW 10% discharge compliance.

Finally, the deadline to submit an initial request letter is within 60 days of the circumstances giving rise to the request or by March 2, 2026, whichever is later.² The Owners’ ongoing consideration of compliance paths is an evolving process, and energy market dynamics factoring into that process are continuing to evolve as well. In an abundance of caution, Cleco submits this initial request letter now and will supplement this request with additional information and developments as necessary.

III. Site and Unit Background

Rodemacher 2 is located at the Brame Energy Center in Lena, Rapides Parish, Louisiana. The unit is jointly owned by LPPA, Cleco Power LLC, and LEPA (the “Owners”) and operates within the Midcontinent Independent System Operator (“MISO”) region. The unit has a capacity of 523 megawatts and has been in commercial operation since 1982. Brame Energy Center manages ELG wastestreams including BATW and leachate. On January 8, 2021, Cleco submitted

² 40 C.F.R. § 423.19(q)(2).

a Notice of Planned Participation (“NOPP”) pursuant to the federal ELG regulations, committing to cease coal combustion by December 31, 2028 (“2028 Subcategory”).

IV. Relevant ELG Background

The 2020 ELG Rule required compliance with a 10% BATW discharge limit by December 31, 2025,³ but allowed facilities to file a NOPP by October 13, 2021 committing to cease coal combustion by December 31, 2028. Facilities that filed a 2028 NOPP did not have to comply with the 10% BATW discharge limit.⁴ Facilities could transfer out of the 2028 NOPP subcategory by December 31, 2025, but if they did so, they must comply with the 10% BATW discharge limit by the December 31, 2025 deadline.⁵

The 2024 ELG Rule retained 10% BATW discharge as an interim limit.⁶ EPA also promulgated longer-term zero-discharge requirements for BATW and other wastestreams in the 2024 ELG Rule.⁷ The original deadline for complying with zero-discharge limits was December 31, 2029, but has since been extended to December 31, 2034.⁸ EPA extended this deadline and others in a final rule published on December 31, 2025.⁹

The ELG Extension Rule finalized in December 2025 also included a new Section 423.18(d) that allowed for the site-specific deadline extensions, including to transfer and to meet the 10% BATW discharge limit, that are now requested by Cleco in this submission and discussed in more detail in Sections VII-VIII. The provisions of the ELG Extension Rule are effective as of today, March 2, 2026.¹⁰

V. Current Compliance Path

The Owners’ current ELG compliance path for Rodemacher 2 is ceasing coal combustion by 2028 and converting the unit to natural gas. As a result of the 2028 NOPP submission, Rodemacher 2 did not have to comply with the outer December 31, 2025, deadline to reduce BATW discharges to no more than 10% system volume on a 30-day average.

The Owners have taken many steps to advance on this path towards meeting the NOPP commitment, including completion of the front-end engineering and design (“FEED”) for gas conversion in 2025, and completing and releasing an engineering, procurement, and construction (“EPC”) performance specification to two bidders in 2025-2026. However, the Owners have

³ 40 C.F.R. § 423.13(k)(2); Steam Electric Reconsideration Rule, 85 Fed. Reg. 64,650, 64,704–05 (Oct. 13, 2020) (“2020 ELG Rule”).

⁴ 40 C.F.R. §§ 423.19(g), 423.13(k)(2)(ii)(A); 2020 ELG Rule at 64,660–61.

⁵ 40 C.F.R. § 423.13(o)(1)(ii); 2020 ELG Rule at 64,708.

⁶ 40 C.F.R. § 423.13(k)(1)-(2); Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 90 Fed. Reg. 40,198, 40,254 (May 9, 2024) (“2024 ELG Rule”).

⁷ 40 C.F.R. §§ 423.13(g)(4)(i), (k)(4)(i), (l)(1)(i); 2024 ELG Rule at 40,199.

⁸ 40 C.F.R. § 423.13(g)(4)(i)(A), (k)(4)(i), (l)(1)(i)(A); Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category—Deadline Extensions, 90 Fed. Reg. 61,328, 61,341 (Dec. 31, 2025) (“ELG Extension Rule”).

⁹ See ELG Extension Rule.

¹⁰ See generally 40 C.F.R. § 423.18(d); ELG Extension Rule at 61,328.

encountered multiple unforeseen, significant circumstances that have driven them to consider alternative compliance pathways for Rodemacher 2, as further detailed in Section VIII.

VI. Alternative Compliance Path

As discussed more fully in Section VIII, significant changes to market dynamics have prompted the co-owners to consider a potential alternative compliance path involving continued coal-fired combustion beyond 2028 at Rodemacher 2. To remain compliant with relevant ELG requirements, however, such extended operations would require LDEQ to authorize extensions to the December 31, 2025, deadlines to (1) transfer out of the 2028 NOPP subcategory and (2) come into compliance with the 10% BATW discharge limit.

With respect to the 10% BATW discharge limit, if the Facility ultimately determines that it will combust coal beyond 2028, the Facility would implement a dry ash handling system for BATW. The Facility has undertaken preliminary assessment of the timing and feasibility to design and install a dry ash handling system, and is currently on track to complete an initial FEED study by the end of March 2026. The currently anticipated schedule for additional activities and completion of a BATW dry handling system is further discussed in Section VIII and attached as Exhibit A. Preliminary cost estimates indicate that this system will be a sizable investment in significantly limiting or fully eliminating BATW discharges if the Facility continues coal-fired operations beyond 2028.

Accordingly, the Facility is making progress towards being in a position to comply with the 10% discharge limit but would need an extension from the original December 31, 2025, deadline to meet that limit and remain in compliance with the ELG regulations.

VII. Regulatory Basis for Deadline Extensions

New provisions in 40 C.F.R. § 423.18 finalized in the December 2025 ELG Extension Rule allow permitting authorities to grant site-specific deadline extensions for (1) transfers between compliance alternatives under the federal ELG regulations and (2) for substantive compliance with ELG limitations finalized in the 2020 and 2024 ELG rulemakings, if facilities requesting the extension meet certain criteria.

The deadline to submit a transfer notice to transfer out of the 2028 Subcategory to the generally applicable requirements was December 31, 2025.¹¹ However, 40 C.F.R. § 423.18(d)(2) now allows LDEQ to grant an extension to this transfer deadline.¹² In explaining the rationale behind these new site-specific deadline provisions, EPA specifically envisioned deadline extensions being granted to plants in the 2028 Subcategory that are now faced with resource adequacy concerns and are considering continued operations, which requires switching out of the 2028 NOPP and back to the generally applicable requirements for BATW. EPA explained that a plant that had submitted a 2028 NOPP “may learn through the IRP process or capacity auctions that its continued operation is necessary to support local resource adequacy” and such plants

¹¹ See 40 C.F.R. §§ 423.13(o), 423.19(l).

¹² See 40 C.F.R. § 423.18(d)(2) (“Transfers pursuant to § 423.13(o)(1)(ii) but receiving alternative § 423.19(l) submission dates in this paragraph (d)(2) shall be deemed timely.”).

“should be given time to both get approvals needed to submit a transfer notice and build out treatment systems to comply with the 2020 rule.”¹³

The deadline to meet the 2020 generally applicable BATW discharge limit was also December 31, 2025. The new site-specific extension provision codified at 40 C.F.R. § 423.18(d)(1) specifically allows permitting authorities to grant “an alternative applicability date and, where appropriate, an associated schedule of milestones, for achieving the required limitations[.]”

For extensions of both transfer notice and substantive requirement compliance deadlines, the Facility must meet one of the four circumstances outlined in 40 C.F.R. § 423.18(d)(3):

<u>Circumstances Warranting Site-Specific Deadline Extensions</u> <u>40 C.F.R. § 423.18(d)(3)</u>
(i) Where a facility needs an alternative applicability date upon making a permissible transfer between limitations prior to the deadlines in § 423.13(o) due to: (A) An unexpected change in regional capacity market prices; or (B) An unexpected change in local demand which materially exceeds projections made in the most recent iterations of integrated resource plans or other planning documents;”
(ii) Where a facility has one or more electric generating units using a wastewater treatment system treating combined wastewater (e.g., wastewater from a single flue gas desulfurization system servicing different units) and needs an alternative applicability date after making a decision to back out of a commitment to permanently cease coal combustion at one or more different electric generating units at the same plant due to: (A) An unexpected change in regional capacity market prices; or (B) An unexpected change in local demand which materially exceeds projections made in the most recent iterations of integrated resource plans or other planning documents;
(iii) Where a facility needs an alternative applicability date because it faces an unexpected supply chain issue that delays a necessary component (not merely a preferred component where there are reasonable substitutes) at a key stage of fabrication or installation such that the timeline for reaching steady-state treatment is delayed; or
(iv) Where a facility faces any other circumstance that requires additional time and is wholly outside both the facility’s control and the facility’s ability to plan for.

¹³ ELG Extension Rule, 90 Fed. Reg. at 61,347–48 (Dec. 31, 2025).

Present circumstances faced by Rodemacher 2 fall within at least two of the described circumstances, § 423.18(d)(3)(i) and (iv), due to recent energy market dynamics and ongoing regulatory changes impacting power plants. In fact, and as discussed above, EPA explicitly designed circumstance (i) for facilities in Rodemacher 2's position.¹⁴

VIII. Significant Unexpected Circumstances Warranting Deadline Extensions

Recent reliability concerns across Louisiana and delays in new generation projects within the MISO South region, where Rodemacher 2 operates, have triggered the need for viable alternatives for keeping units on the grid. Combined with recent and impending regulatory changes impacting power plants, these demand changes and reliability concerns warrant extensions to the ELG deadlines for Rodemacher 2 under the new 40 C.F.R. § 423.18(d)(3).

A. Market Demand and Price Changes:

Three key developments since the Facility filed its 2021 NOPP submission have significantly impacted demand in MISO and underscored the need for continued reliable and dispatchable power sources: (1) load growth driven by data center demand and industrial development,¹⁵ (2) extreme weather events that have strained grid operations,¹⁶ and (3) retirements by other power plants in the region.¹⁷

This rapid MISO South load growth (driven by industrial development and data center demand),¹⁸ combined with accelerating retirements outpacing replacement generation, has materially tightened reserve margins. Further, between 2024 and 2025, MISO South experienced a significant increase in declared emergency events, driven by severe weather and conservative operations.¹⁹ MISO has also reduced seasonal accreditation for intermittent resources—resources

¹⁴ See ELG Extension Rule, 90 Fed. Reg. at 61,347–48 (“[A] plant that had submitted a [2028 NOPP] may learn through the IRP process or capacity auctions that its continued operation is necessary to support local resource adequacy... the plant should be given time to both get approvals needed to submit a transfer notice and build out treatment systems to comply with the 2020 rule.”).

¹⁵ See DOE, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electrical Grid (July 2025) (“DOE Resource Adequacy Report”) at 1 (“The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management.”).

¹⁶ See Testimony of Jennifer Curran of MISO, “Keeping the Lights on: Examining the State of Regional Grid Reliability” Before the House Committee on Energy and Commerce, Subcommittee on Energy (Mar. 25, 2025) at 6 (“MISO’s region, like most of the country, is also experiencing changing weather patterns, including more frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country. These extreme weather events create challenging operating conditions, with high demand for electricity sometimes accompanied by reduced solar or wind output and, in some instances, challenges with adequate fuel supplies for natural gas and coal power plants. This highlights the need for a diverse electric generation fleet and a robust transmission system to move energy over long distances.”).

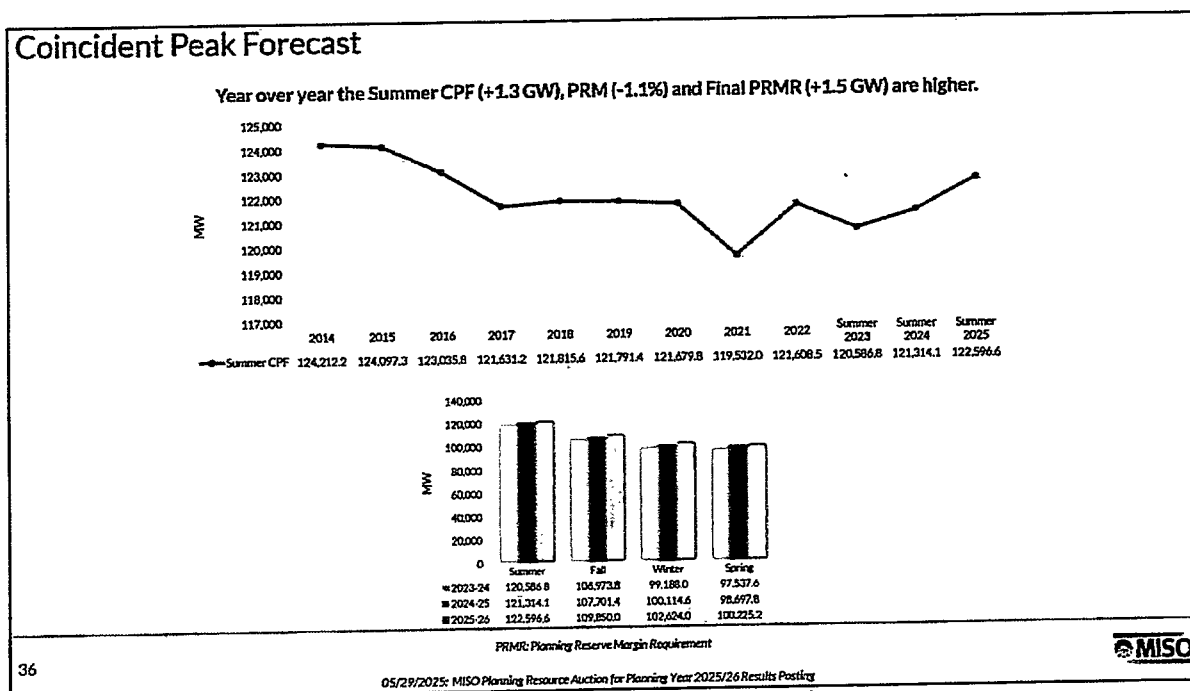
¹⁷ *Id.* (“The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the ‘plant closures’ scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.”).

¹⁸ See MISO, “2024 Load Forecast and Process Enhancements Workshop” (Dec. 18, 2024) at 18 (“Projected load growth from all forms of electrification within MISO’s footprint is expected to be approximately three times higher than previously forecasted,” depicting industry development and data centers as significant contributors to higher projections.).

¹⁹ See generally MISO, “Notifications Overview – Real-Time Operations.”

that comprised 93% of the 2023–24 interconnection queue—leading to reduced accredited capacity in critical summer and winter seasons.²⁰ These conditions have increased the frequency of capacity advisories and indicate the market is approaching its operational limits.²¹

For example, 2025 data from the MISO Planning Resource Auction for Planning Year 2025/26 Results detail significant constraints and reliability concerns.²² As depicted below, the Summer Coincident Peak Forecast increased by approximately 1.3 GW compared to the prior year, while the Final Planning Reserve Margin Requirement rose by 1.5 GW. The increase in the coincident peak forecast directly evidences load growth within the MISO footprint, which MISO has identified as an ongoing challenge through its Reliability Imperative initiatives.²³



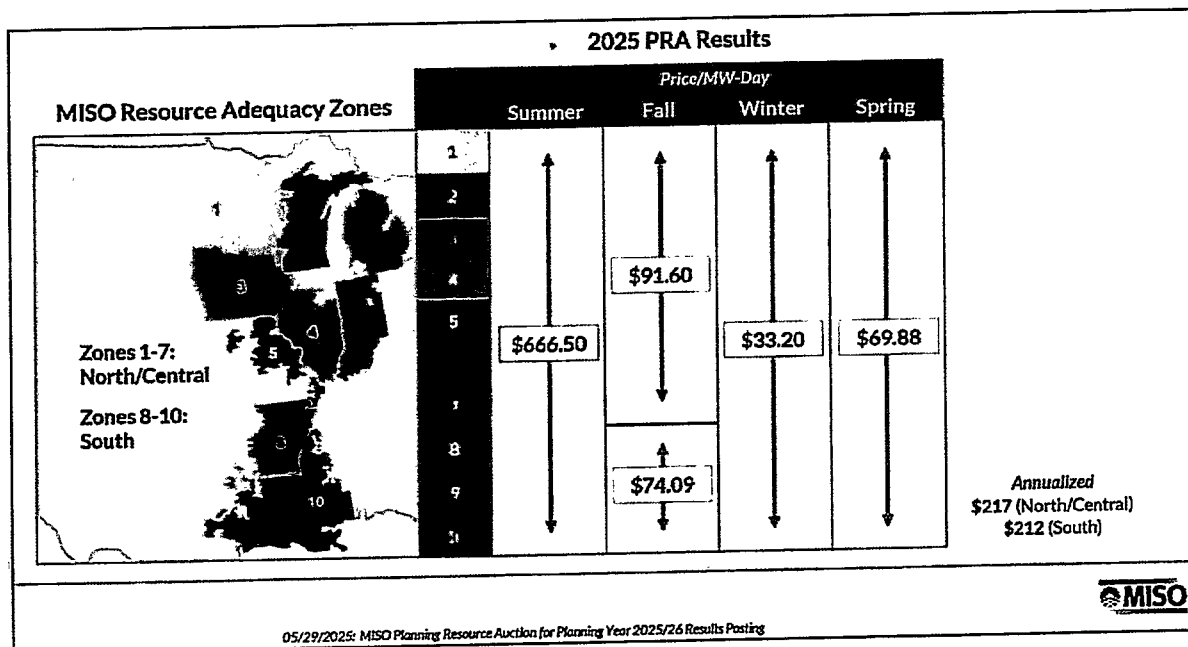
²⁰ See MISO, “MISO announces Generator Interconnection Queue cycle results” (Apr. 23, 2024); 2025 OMS-MISO Survey Results (Jun. 6, 2025).

²¹ See DOE, Order No. 202-26-16 (Feb. 17, 2026) (“an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes”); Exec. Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid” (Apr. 8, 2025); Exec. Order 14156, “Declaring a National Emergency” (Jan. 20, 2025).

²² MISO, Planning Resource Auction Results for Planning Year 2025-26 (“PRA Results”).

²³ PRA Results at 7, 36.

As shown in the below visual from the PRA Results, in 2025, while MISO achieved sufficient capacity at the regional, subregional, and zonal levels, the summer clearing price of \$666.50 per MW-day reflects the highest reliability risk and a notably tighter supply-demand balance. This represents a substantial price signal compared to non-summer seasons, with fall prices at \$91.60 (North/Central) and \$74.09 (South), winter at \$33.20, and spring at \$69.88. These pricing dynamics directly support reliability concerns because they signal that available surplus capacity is diminishing relative to demand. The elevated summer prices, in particular, indicate that the grid faces heightened risk during peak demand periods, thereby justifying the retention of dispatchable generation resources, including coal combustion units, to maintain system stability and meet planning reserve requirements.



Further, there has been a dramatic escalation in prices in recent years, as shown below from the PRA Results. The data reveals that summer clearing prices have increased exponentially in recent years, rising from \$10.00 per MW-day in Summer 2023 to \$30.00 in Summer 2024, and then surging to \$666.50 in Summer 2025. This represents a 2,122% increase over just two planning years. Prior to this recent escalation, summer prices remained relatively modest, with historical clearing prices ranging from \$1.00 to \$257.53 across various zones during the 2015-2022 period.

Historical Summer Auction Clearing Price Comparison											
PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016		\$3.48		\$150.00		\$3.48		\$3.29		N/A	N/A
2016-2017	\$19.72			\$72.00					\$2.99		N/A
2017-2018					\$1.50						N/A
2018-2019	\$1.00					\$10.00					N/A
2019-2020			\$2.99			\$24.30		\$2.99			
2020-2021			\$5.00			\$257.53	\$4.75	\$6.88	\$4.75	\$4.89-\$5.00	
2021-2022			\$5.00					\$0.01		\$2.78-\$5.00	
2022-2023			\$236.66					\$2.88		\$2.88-236.66	
Summer 2023						\$10.00					
Summer 2024						\$30.00					
Summer 2025						\$666.50					

• Auction Clearing Prices shown in \$/MW-Day

27

ERZ: External Resource Zones

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

MISO

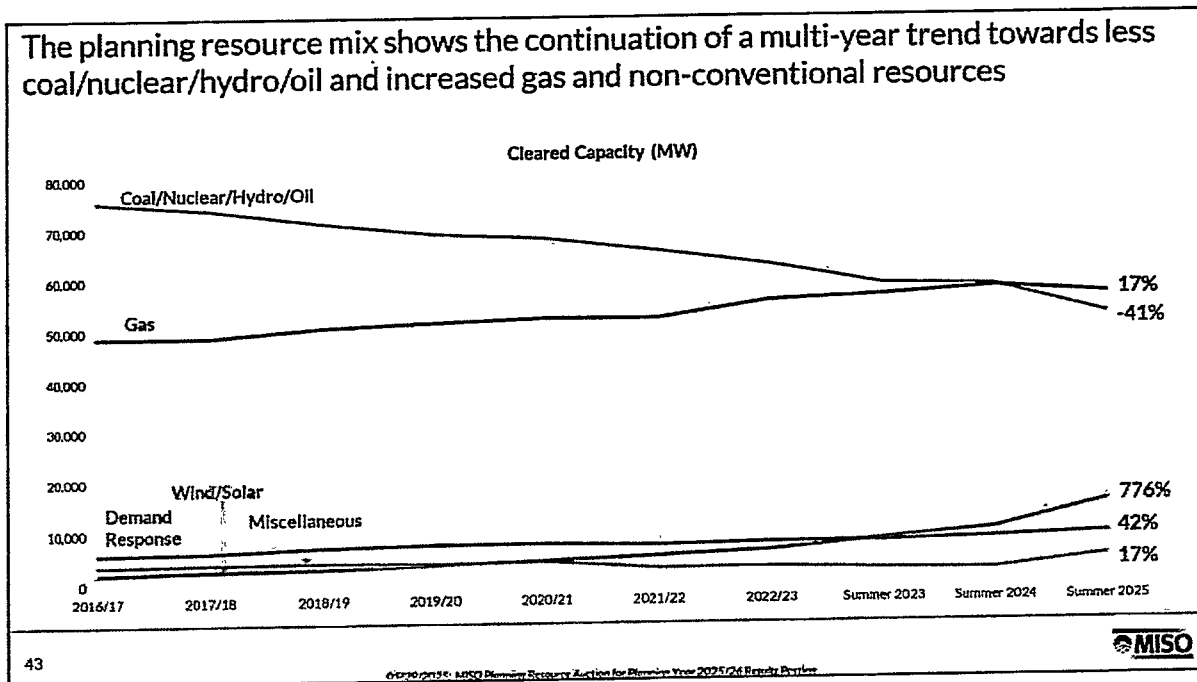
To support a reliable supply of energy in the MISO region, continued operation of Rodemacher 2 is necessary. In contrast to natural gas, there are advantages to coal-fired generation and specifically operation of the existing coal-fired unit Rodemacher 2. Performance (including generation, emissions, and operation and maintenance) is well known, along with the expected operating capacity of the unit. By contrast, there are some risks for units converting to gas due to uncertainties regarding whether the unit will perform as claimed with respect to generating capacity, emissions, and expected operation and maintenance. Moreover, coal is stored on site and readily available. Due to bulk purchasing, the cost is stable over a given period of time. By contrast, natural gas may not be available in adequate quantities in some cases, and the cost of gas may fluctuate.

The graph below illustrates a multi-year shift in MISO's generation portfolio away from traditional baseload resources toward gas and non-conventional resources. This transition occurs against a backdrop of reliability challenges including reduced surplus capacity, which has declined from approximately 6.5 GW in 2023 to 4.6 GW in 2024 to just 2.6 GW in 2025—a 60% reduction over two years.²⁴ MISO has acknowledged that the "majority of new resources [have] variable, intermittent output and high weather correlation," which presents distinct reliability challenges.²⁵ The retirement or suspension of dispatchable coal combustion units, amid a transition to intermittent resources, could exacerbate capacity shortfalls during periods of peak demand or adverse weather conditions. Meanwhile, the retention of coal combustion units like Rodemacher

²⁴ PRA Results at 4.

²⁵ PRA Results at 7.

2 provides firm, dispatchable capacity that helps offset the variability of renewable resources and maintain grid stability.



Accordingly, these unexpected and evolving energy market dynamics fall within the circumstances under 40 C.F.R. § 423.18(d)(3)(i) and (iv) that warrant the requested deadline extensions.

B. Regulatory Flux:

The ELG regulations, and other regulations impacting coal-fired power plant operations, continue to undergo significant changes that impact facilities' ability to reliably plan for coal cessation and/or conversion. In 2024—three years after Cleco submitted the 2028 NOPP—EPA finalized revisions to the federal ELG regulations, which included establishing stringent zero-discharge standards for BATW, flue gas desulfurization (“FGD”) wastewater, and combustion residual leachate (“CRL”) from coal-fired power plants.²⁶ Further significant shifts in the regulatory landscape are currently underway. On March 12, 2025, the EPA announced plans to reconsider the 2024 ELG Rule.²⁷ In October 2025, the agency proposed extending compliance deadlines and adding flexibility provisions, including the site-specific deadline extensions sought in this letter.²⁸ On December 23, 2025, the EPA published a final ELG Extension Rule that significantly extended compliance timelines for coal-fired power plants, citing the need to “provide flexibility to a critical industry in advance of imminent deadlines, which could otherwise force utilities to make premature and irrevocable decisions to begin the process of decommissioning

²⁶ 2024 ELG Rule, 90 Fed. Reg. 40,198.

²⁷ EPA, “EPA Announces It Will Reconsider 2024 Water Pollution Limits for Coal Power Plants to Help Unleash American Energy” (Mar. 12, 2025).

²⁸ 90 Fed. Reg. 47,693 (Oct. 2, 2025).

without full consideration of rapidly evolving regional resource adequacy needs.”²⁹ As a result of the national energy crisis driven by substantial increases in electricity demand, EPA determined it was justified to give facilities more time to assess their compliance options and future operational plans. EPA has also indicated that it is considering additional changes to zero-discharge limits and technology-based standards in future rulemakings.

Beyond federal ELG regulations, coal-fired power plants are experiencing significant regulatory upheaval in several areas where significant rulemakings were finalized in 2024, including coal combustion residuals (“CCR”), mercury and air toxic standards (“MATS”), and greenhouse gas (“GHG”) emission standards. In May 2024, EPA finalized regulations that drastically expanded the CCR regulatory landscape to regulate CCR surface impoundments at inactive facilities (“legacy surface impoundments”) and all placements of CCR on land of one ton or more (“CCR management units” or “CCRMUs”) (the “Legacy/CCRMU Rule”).³⁰ In March 2025, EPA announced its plans to reconsider the same Legacy/CCRMU Rule,³¹ and has since then finalized deadline extensions applicable to the new CCRMU regulations as it continues to reconsider the substantive requirements of the final rule.³²

In 2024, EPA also finalized amendments to MATS and GHG emission standards, which are now being reconsidered and revised. The 2024 MATS amendments tightened the filterable particulate matter (“fPM”) emission standard from 0.030 lb/MMBtu to 0.010 lb/MMBtu, reduced the mercury standard for lignite-fired plants by 70%, and mandated continuous emissions monitoring systems (“PM CEMS”) for all coal-fired electric generating units.³³ In June 2025, EPA proposed to repeal these 2024 amendments due to technical feasibility concerns and unreasonable compliance costs.³⁴ The proposal would revert to the 2012 MATS, and EPA finalized this repeal in February 2026.³⁵

In 2024, EPA also finalized a suite of regulations aimed at reducing GHG emissions from new and existing EGUs under Clean Air Act (“CAA”) Section 111, which are currently being reconsidered and rolled back.³⁶ The 2024 GHG standards included repealing the Affordable Clean Energy Rule, establishing GHG emission guidelines for existing fossil fuel-fired electric-generating units (“EGUs”), and setting new source performance standards (“NSPS”) for GHG emissions from new, modified, and reconstructed fossil fuel-fired EGUs. In June 2025, EPA proposed repealing all GHG emissions standards for fossil fuel-fired power plants, offering two alternative approaches: a finding that GHG emissions from power plants do not “contribute significantly” to dangerous air pollution at a level sufficient to invoke the Agency’s authority under CAA Section 111, or a narrower repeal of specific portions of the GHG standards based on

²⁹ ELG Extension Rule, 90 Fed. Reg. at 61,339.

³⁰ Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments, 89 Fed. Reg. 38,950 (May 8, 2024) (“Legacy/CCRMU Rule”).

³¹ EPA, “EPA Announces Swift Actions on Coal Ash Program” (Mar. 12, 2025).

³² Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; CCR Management Unit Deadline Extension Rule, 91 Fed. Reg. 5,806 (Feb. 10, 2026) (“CCRMU Extension Rule”).

³³ See National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review, 89 Fed. Reg. 38,508 (May 7, 2024) (“2024 MATS Rule”).

³⁴ See 90 Fed. Reg. 25,535 (June 17, 2025).

³⁵ See 91 Fed. Reg. 9,088 (Feb. 24, 2026).

³⁶ See 89 Fed. Reg. 39,798 (May 9, 2024).

determinations that carbon capture and sequestration has not been "adequately demonstrated" as a best system of emission reduction ("BSER").³⁷ EPA has yet to finalize any repeal.

Overall, these examples of regulatory flux demonstrate many ways coal-fired power plants' cessation and/or conversion plans have been meaningfully impacted. Facilities like Rodemacher 2 undertake their long-term planning in part based on the impact of current and anticipated regulations, but significant regulatory upheaval impedes facilities' ability to reliably plan. Here, Rodemacher 2 submitted the NOPP in 2021 committing to a 2028 coal cessation date; five years later, the regulatory landscape looks significantly different and is still in flux, prompting the Owners to reasonably reconsider long-term plans to ensure reliable and cost-effective supply of energy against the new regulatory backdrop.

C. Conclusion:

Due to pressing market reliability concerns, rapid load growth, retirements, and regulatory flux, the Owners are now evaluating the viability of continuing coal operations at Rodemacher 2. However, this alternative compliance path would require site-specific deadline extensions under 40 C.F.R. § 423.18(d) in order to remain in compliance with federal ELG regulations and the Facility's LPDES permit. As discussed above, the Facility qualifies for such an extension under both 40 C.F.R. § 423.18(d)(i) and (iv).

IX. Proposed Compliance Schedule & Basis

Cleco proposes the following compliance schedule:

- Within **90 days** of LDEQ confirming both deadline extensions, Cleco will provide formal notice of transfer out of the 2028 Subcategory and into the generally applicable ELG limitations.
- Within **120 days** of Cleco's transfer notice, Cleco will submit a permit modification request to incorporate the transfer and to establish a new BATW 10% compliance deadline.
- Rodemacher 2 will comply with the BATW 10% discharge limitation by **December 31, 2029**.

In support of the proposed December 31, 2029, date for substantive compliance with the BATW 10% limitation, an engineering dependency chart is attached as Exhibit A showing the anticipated timeline to design, install, and test a dry ash handling system at the Facility. The anticipated timeline (approximately 44 months) is consistent with input EPA received from other power companies as EPA was promulgating various revisions to the ELGs; estimates typically ranged from 32 to 48 months.³⁸ More detail is provided in the attached Exhibit A, and a high-level summary of the key milestones is provided below, with construction complete by December 2029:

³⁷ 90 Fed. Reg. 25,752 (June 17, 2025).

³⁸ CCR Part A Rule, 85 Fed. Reg. 53,516, 53,523 ("EPA proposed that the average amount of time needed to implement the conversion to dry handling is 36 months, although the proposed rule presented information that times ranged from 36 to 48 months."); 2024 ELG Rule, 89 Fed. Reg. at 40,283 note 223 ("Information in the record indicates

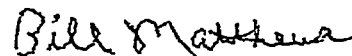
- All relevant milestones based on an estimation that LDEQ approves the requests in this letter to continue coal combustion by late Q2 2026;
- An additional FEED study is scheduled to run for 148 days beginning in early Q3 2026, following LDEQ approval;
- If necessary, preparation and review/approval of relevant environmental permit applications and Louisiana Public Service Commission ("LPSC") testimony filings are estimated to be completed by Q2 2027;
- Award of major equipment contracts is expected by May 2028;
- Outage construction is forecasted to begin in November 2029 with an estimated 8-week construction duration and completion by December 2029; and
- Project completion (remaining ancillary items after construction is complete in December 2029) is forecasted by February 2030.

Note that the timing of an LDEQ approval of this request drives the project schedule, and the Facility is in the process of conducting an initial FEED study. Accordingly, the time estimates above and in Exhibit A are preliminary. The initial FEED study is currently anticipated to be completed in late March 2026. If the initial FEED study (or subsequent FEED studies or other developments) substantially alters the timeframes set forth in this letter, Cleco will submit a supplement/update for LDEQ's consideration.

X. Conclusion

We appreciate LDEQ considering this request. If there are any questions regarding the contents of this letter, please contact me at william.matthews@cleco.com or 318-484-7718.

Respectfully submitted,



Bill Matthews
Director – Environmental Policy and Planning
Cleco Power LLC

that most facilities should be able to complete all steps to implement changes needed to comply with the BA transport water requirements within 32 to 35 months"); *id.* at 40,256 ("Information in EPA's rulemaking record indicates that a typical timeframe to raise capital, plan and design systems (including any necessary pilot testing), procure equipment, and construct and test systems falls well within the existing five-year permit cycle.").

EXHIBIT A

[illegible]

EXHIBIT RB-3

LDEQ RESPONSE LETTER

JEFF LANDRY
GOVERNOR



COURTNEY J. BURDETTE
SECRETARY

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL SERVICES

RCVD APR 23 2026

APR 17 2026

CERTIFIED MAIL-9589 0710 5270 3727 1983 61-RETURN RECEIPT REQUESTED

File No.: LA0008036
Agency Interest Number (AI No.): 2922
Activity No.: PER20260001

Mr. Bill Matthews
Cleco Power, LLC
Brame Energy Center
Post Office Box 5000
Pineville, LA 71361-5000

RE: Request for Extension of Site-Specific Effluent Limitation Guidelines (ELG) Deadlines in
LA0008036

Dear Mr. Matthews:

This Office is in receipt of a letter dated March 2, 2026, requesting two site specific extensions under 40 CFR 423.18(d) applicable to LPDES permit LA0008036 for Cleco Power, LLC (Cleco)- Brame Energy Center's Rodemacher 2. Cleco requests an extension of the December 31, 2025, deadline to transfer out of the 2028 ELG coal cessation subcategory pursuant to 49 CFR 423.28(d)(2) and an extension of the December 31, 2025, deadline to comply to with generally applicable bottom ash transport water (BATW) limitation to limit dischargers to 10% of the bottom ash system volume, pursuant to 40 CFR 423.18(d)(1).

Under LPDES permit LA0008036 effective December 1, 2025, the compliance path is ceasing coal combustion by 2028 and converting the unit to natural gas. Consequently, Rodemacher 2 did not have to comply with the outer December 31, 2025, deadline to reduce BATW discharges to no more than 10% system volume on a 30-day average. EPA promulgated new provisions in the final December 2025 ELG extension rule which allows for site-specific deadline extensions for (1) transfers between compliance alternatives under the federal ELG regulations and (2) for substantive compliance with ELG limitations finalized, in the 2020 and 2024 ELG rulemaking, if facilities requesting the extension meet certain criteria.

Cleco stated that the extension is necessary due to recent reliability concerns across Louisiana and delays in new generation projects within the Midcontinent Independent System Operator (MISO) South region which have created the need for viable alternatives for keeping the unit on the grid. Additionally, Cleco stated that the recent and expected regulation changes potentially impacting power plants warrant the extensions to the ELG deadlines under 40 CFR 423.18(d)(3).

Cleco is proposing the following compliance schedule:

1. Within 90 days of LDEQ confirming the extensions, Cleco will provide a formal notice of transfer out of the 2028 subcategory and into the generally applicable ELG limitations;
2. Within 120 days of Cleco's transfer notice, Cleco will submit a permit modification request to incorporate the transfer and to establish a new BATE 10% compliance deadline; and

Cleco Power, LLC
RE: LA0008036, AI No. 2922
Page 2

3. Rodemacher 2 will comply with the BATW 10% discharge limitation by December 31, 2029.

This Office has no objection to extending December 31, 2025, deadline to transfer out of the 2028 ELG coal cessation subcategory and the December 31, 2025, deadline to comply to with generally applicable BATW limitation to limit dischargers to 10% of the bottom ash system volume. Furthermore, LDEQ approves Cleco's proposed compliance schedule.

Should you have any questions concerning this matter feel free to contact Amy Exnicios, Office of Environmental Services, Permits Division, by phone at (225) 219-3501 or by email at amy.exnicios@la.gov. To ensure that all correspondence regarding this facility is properly filed, please reference your AI No. 2922 and LPDES permit number LA0008036 on all future correspondence to this Department.

Sincerely,



Jenniffer Sheppard, Administrator
Water Permits Division

ale

c: IO-W

ec: Permit Compliance Unit
Acadiana Regional Office
Office of Environmental Compliance

Amy Exnicios
Kelli Hamilton
Scott Causey
Water Permits Division

EXHIBIT RB-4

PROJECT SCHEDULE

REDACTED TO OMIT CONFIDENTIAL,
COMPETITIVELY SENSITIVE, TRADE SECRET,
AND PROPRIETARY INFORMATION PURSUANT
TO RULE 12.1 OF THE COMMISSION'S
RULES OF PRACTICE AND PROCEDURE