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BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In Re:)
Georgia Power Company's) Docket No. 56765
Fuel Cost Recovery (FCR-27))

Volume I

Hearing in Room 110
244 Washington Street
Atlanta, Georgia

Tuesday, May 5, 2026

The hearing was called to order, pursuant to Notice at
9:40 a.m.

PRESENT WERE:

JASON SHAW, Chairman
LAUREN "BUBBA" MCDONALD, Vice-Chairman
TRICIA PRIDEMORE, Commissioner
PETER HUBBARD, Commissioner
DR. ALICIA M. JOHNSON, Commissioner - (via Zoom)

ATHENS REPORTING, LLC
490 N. Thomas Street
Athens, Georgia 30601
(770) 225-7663
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1 APPEARANCES:

2 On behalf of Georgia Public Service
3 Commission:

4 JUSTIN PAWLUK, ESQ.
5 CHRIS COLLADO, ESQ.
6 Georgia Public Service Commission
7 244 Washington Street, SW
8 Atlanta, Georgia 30334

9 On behalf of Georgia Power Company:

10 STEVEN J. HEWITSON, ESQ.
11 ALLISON PRYOR, ESQ.
12 HOLLY R. INGRAM
13 Troutman Pepper Locke
14 Bank of America Plaza
15 600 Peachtree Street, NE
16 Suite 5200
17 Atlanta, Georgia 30308-2261

18 On behalf of Georgia Association of
19 Manufacturers:

20 CHARLES B. JONES, III, ESQ.
21 JIM KELLEHER
22 The Hurt Building
23 50 Hurt Plaza
24 Suite 1620
25 Atlanta, Georgia 30303

On behalf of Georgia Interfaith Power &
Light and Southface Energy Institute:

JENNIFER WHITFIELD, ESQ.
BOB SHERRIER, ESQ.
AMITAV KAMANI, ESQ.
Southern Environmental Law Center
Ten 10th Street NW
Suite 1050
Atlanta, Georgia 30309

1 On behalf of Metropolitan Atlanta Rapid
2 Transit Authority (MARTA):

3 ROBERT B. BAKER, ESQ.
4 Robert B. Baker, PC
5 2480 Briarcliff Road NE
6 Suite 6
7 Atlanta, Georgia 30329

8 On behalf of Resource Supply Management:

9 JIM CLARKSON
10 135 Emerald Lake Road
11 Columbia, South Carolina 29209

12 On behalf of Sierra Club, Southern Alliance
13 For Clean Energy and The Natural Resources
14 Defense Council:

15 ISABELLA ARIZA, ESQ.
16 MAGGIE SHOBER
17 PATRICK KING II
18 Sierra Club
19 50 F Street NW
20 8th Floor
21 Washington, D.C. 20001

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1 CHAIRMAN SHAW: Good morning again. Thank
2 y'all for being with us. Thank you for bearing
3 with us, as we had to do our administrative session
4 earlier. We'll go ahead and call this hearing to
5 order. This is Docket No. 56765, Georgia Power
6 Company's Fuel Cost Recovery. We will start by
7 calling for appearances.

8 Georgia Public Service Commission.

9 MR. PAWLUK: Good morning, Commissioners.
10 Justin Pawluk and Chris Collado for PIA Staff.

11 CHAIRMAN SHAW: Morning.

12 Georgia Power.

13 MS. PRYOR: Good morning, Commissioners.
14 Alison Pryor, Steve Hewitson and Holly Ingram on
15 behalf of Georgia Power Company.

16 CHAIRMAN SHAW: Georgia Association of
17 Manufacturers.

18 MR. JONES: Good morning, Mr. Chairman. Clay
19 Jones on behalf of Georgia Association of
20 Manufacturers.

21 CHAIRMAN SHAW: Good morning.

22 Georgia Interfaith Power & Light and
23 Southface Institute.

24 MR. KAMANI: Good morning, Commissioners.
25 Amitav Kamani, Jennifer Whitfield and Bob Sherrier

1 on behalf of Georgia Interfaith Power & Light and
2 Southface Institute.

3 CHAIRMAN SHAW: Good morning.

4 Metropolitan Atlanta Rapid Transit Authority,
5 MARTA.

6 MR. BAKER: Robert Baker on behalf of Marta.

7 CHAIRMAN SHAW: Resource Supply Management.

8 (No response.)

9 Resource Supply Management?

10 (No response.)

11 Sierra Club, Southern Alliance for Clean
12 Energy, and the Natural Resources Defense Council.

13 MS. ARIZA: Good morning, Commissioners.

14 Isabella Ariza on behalf of Sierra Club and NRDC.

15 CHAIRMAN SHAW: All right. Any others?

16 (No response.)

17 We had a late intervention application
18 yesterday from Georgia WAND. Are they here today?

19 (No response.)

20 CHAIRMAN SHAW: All right. We'll move on.

21 Are there any housekeeping matters to take up?

22 (No response.)

23 All right. We have a sign-up sheet for
24 public witnesses, and we did have some folks that
25 took the time to be with us this morning. So this

1 is the time when we'll call up public witnesses.
2 And I'll just remind everyone that the clock will
3 be displayed so you'll know your -- where your
4 three minutes is at. So we appreciate your respect
5 for that. We have -- we'll just go -- I'll go down
6 the list. And what I'll do is call your name, and
7 then I'll call the name of the person that'll be up
8 next, so you'll know to be ready.

9 And we'll start with Dorothy Simpson. And we
10 appreciate y'all being here with us. Yes, ma'am.
11 Come on up. Welcome.

12 MS. SIMPSON: The first time here, never been
13 here before.

14 CHAIRMAN SHAW: Welcome.

15 MS. SIMPSON: Never did this before.

16 CHAIRMAN SHAW: Followed by Mark Ivey. Sorry
17 about that. Go ahead.

18 MS. SIMPSON: Sorry.

19 CHAIRMAN SHAW: Go ahead.

20 MS. SIMPSON: I can go ahead? Next -- Next
21 General Electric Service, a contractor authorized
22 by Georgia Power. Georgia Power upgraded my house
23 outside meter. When my house has no certification
24 of occupancy, unqualified and invalid deed stamp.
25 And in accordance to a covenant Deed Book 48 316d,

1 page 6680 -- lot -- landlocked 999th district has a
2 hold on my house, plat 106, plat -- page plat book
3 106, plat page 79, certification of occupancy.

4 Georgia Power upgraded my house outside meter
5 with a 200-watt upgrade. The address 5173 High
6 Point Road, Union city, Georgia, when my house
7 indoor electrical panel is 120 watt. A Federal
8 Pacific panel overheating and not tripping in
9 accordance to California, kind of burned up
10 everything out there. After installation of the
11 200-watt upgrade, my whole side of my electrical
12 plugs not working, the static in my TV is un- -- I
13 can't even watch no TV.

14 I fear for my life. I just want to know who
15 approved that deathtrap, and no electrician could
16 analyze this until I get an upgrade. It's going to
17 cost me \$18,000 in -- in -- over \$18,000. My
18 question to the board: Who pays since Georgia
19 Power own the meter and the service? And I had no
20 warning of this danger from my city or no one.

21 CHAIRMAN SHAW: Yeah. Hey, Ms. Simpson, is
22 that something that you had already called our
23 consumer unit about, or do we have a record --

24 MS. SIMPSON: I did. I did. But my computer
25 is down.

1 CHAIRMAN SHAW: Okay.

2 MS. SIMPSON: Everything is down. So I don't

3 know the -- I'm sorry to --

4 CHAIRMAN SHAW: No, you're fine.

5 MS. SIMPSON: -- interfere, but I need some

6 help. And I want to know who approved that

7 deathtrap.

8 CHAIRMAN SHAW: Well, ma'am, let's try to get

9 you some help while you're here today. Okay?

10 So if Ms. Sallie, Erica, if you can help her,

11 and then get somebody from Georgia Power, and let's

12 help get her some answers. Thank you.

13 COMMISSIONER PRIDEMORE: Come to the hall,

14 ma'am, and we'll get all your information.

15 CHAIRMAN SHAW: All right. Mark Ivey,

16 followed by Christian Sigman.

17 MR. IVEY: Good morning.

18 CHAIRMAN SHAW: Good morning.

19 MR. IVEY: Thank you, Mr. Chairman,

20 Commissioners. I appreciate the opportunity to

21 speak before you today. My name is Mark Ivey, and

22 my family has built homes in Columbia County and

23 the greater Augusta region for decades. We built

24 in one of the fastest growing parts of Georgia near

25 Plant Vogtle, near Fort Gordon, and now near some

1 of the economic development opportunities,
2 including the data centers that are proposed for
3 Columbia County that will reshape our region.

4 As a homebuilder, I think a lot about
5 foundations, because whether you're building a
6 house, a neighborhood or a community, if the
7 foundation isn't solid, nothing else works the way
8 it should for us. One of those foundations is
9 reliable and affordable electricity.

10 When families buy a home, they're not just
11 buying square footage, they're buying stability,
12 predictability, confidence that when they flip a
13 switch, the lights come on, that their mortgage,
14 their insurance, their utility bills can all work
15 together in a family budget.

16 And in our part of Georgia, we've seen
17 firsthand how important that reliability is.
18 Hurricane Helene didn't just impact trees and power
19 lines. It disrupted lives, construction schedules,
20 businesses, families. And it's in moments like
21 that that you find out what kind of systems you
22 have and what kind of partners you have.

23 We watch Georgia Power crews and support
24 teams respond under extraordinary, difficult
25 conditions, restoring service and helping

1 communities recover when it mattered most. That
2 kind of resilience matters to builders because
3 recovery and certainty matter.

4 Fuel costs, like so many costs in
5 construction, went up significantly during
6 inflationary years. We all felt it. But just like
7 material prices can stabilize, when fuel costs come
8 down, customers deserve to benefit from that too.
9 That's why I appreciate this fuel reconciliation
10 process.

11 If this proceeding helps lower bills, even
12 modestly, while maintaining the strength and
13 reliability of the grid, that matters, not because
14 a few dollars changes everything overnight, but
15 because predictability builds confidence,
16 confidence for families buying homes, confidence
17 for businesses expanding, confidence for
18 communities preparing for growth. In Augusta's
19 region, we understand growth is coming from energy,
20 from industry, from innovation. But growth only
21 works if the grid is ready, resilient and
22 responsibly managed.

23 From where I sit, Georgia Power's approach
24 investing in reliability, recovering responsibly
25 from storms and reconciling fuel costs fairly is

1 part of keeping that foundation strong, and strong
2 foundations build strong homes, strong communities
3 and a stronger Georgia.

4 Thank you for your time.

5 CHAIRMAN SHAW: Thank you for taking the time
6 to be with us.

7 All right. Christian Sigman, followed by
8 Michelle Girtman.

9 Morning.

10 MR. SIGMAN: Good morning, Mr. Chair, and
11 Commissioners.

12 First of all, thank you for your service.
13 I'm Christian Sigman, city manager in Brookhaven,
14 Georgia.

15 Georgia Power has been a great partner for us
16 on really two fronts, one is sustainability. We
17 take it very seriously on many different levels,
18 not just environmental, but organizational and
19 financially. And they've been a great partner in
20 that -- in that we -- a lot of people don't know
21 this, but Brookhaven has more electric cars per
22 capita registered in Georgia than any other city in
23 Georgia. So we lead the state in EV charger
24 implementation, and Georgia has been a great
25 part -- Georgia Power has been a great partner with

1 that.

2 With that comes the sustainability of
3 multi-generation -- generation sources. That's
4 well above my pay grade, but I get enough
5 information from my representatives at Georgia
6 Power to know that they take it very seriously, the
7 way they balance their fuel costs and their fuel
8 sourcing, if you will.

9 I go through that in my line of work. We're
10 all dealing with higher gas prices right now. I
11 have police cars. We spend \$250,000 a year in
12 gasoline. We've got to worry about where we're
13 going to get our gasoline from.

14 From what I understand, the fuel costs, they
15 don't make money off it. So really, to my -- this
16 is kind of administrative. And I'm glad that
17 process is here, because in many cases in the
18 private sector when you see these price increases,
19 when things come back down, the prices of Pop-Tarts
20 don't come back down.

21 In this case, fuel costs will reflect their
22 actual costs. So I support this docket item, which
23 is 56765, and I'm glad this process is in place to
24 protect the ratepayers, but also, quite frankly, to
25 protect Georgia Power and other utilities to make

1 sure they have the flexibility not to be
2 administratively penalized when they do have to
3 raise rates when fuel costs go up.

4 On the fuel -- the recovery for natural
5 disasters, wonderful partnership with Georgia Power
6 there as well. We help stage their vehicles during
7 big storms. We get a call two or three days
8 beforehand. We are notified of what's going on.
9 We tell our residents, but we also house and stage
10 utility trucks from all over the region, right
11 there in Blackburn Park in Brookhaven.

12 So when there is an event, they can get out
13 into the community, not just Brookhaven, not just
14 North DeKalb, not just even North Atlanta, all of
15 Georgia and all of the service area. And I
16 appreciate, as a city administrator who realizes
17 the importance of mutual aid with my neighbors,
18 that mutual aid that Georgia Power has with all the
19 other utility companies, the parent company,
20 Southern Corporation, is huge for the viability of
21 our community. So as they incur those costs, we
22 support that they get recovered for that as well.

23 Again, I thank you for your service. Public
24 Service Commission in every state that I've worked
25 in is a very, very important partner of what we do

1 in local administration, and I look forward to
2 y'all supporting the two items that are on the
3 agenda today. Thank you.

4 CHAIRMAN SHAW: Thank you, sir. I appreciate
5 all you do up there in Brookhaven.

6 Michelle Girtman, followed by Frank Bove.

7 MS. GIRTMAN: Good morning, Mr. Chairman.

8 CHAIRMAN SHAW: Hey, good morning. How are
9 you doing?

10 MS. GIRTMAN: Doing good. How are you?

11 CHAIRMAN SHAW: Good to see you. This is
12 south Georgia girl.

13 MS. GIRTMAN: South Georgia, south Georgia.
14 Yes. My name is Michelle Girtman, and I've been
15 the executive director for The Haven in Valdosta,
16 serving nine counties for 18 years and in Waycross
17 as the executive director, serving the Magnolia
18 House Shelter for abused women and children for 31
19 years. So a little bit old.

20 In 2017, I flew to Fort Worth, Texas, to look
21 at a project called a Family Justice Center. And
22 when I got there, I saw a dream that I probably
23 could never make happen. So I came back and during
24 the COVID years got to thinking about how we could
25 help victims of domestic violence and how we could

1 better serve our communities. And it was kind of
2 like a one-stop shop. Think about a Costco or a
3 Sam's where you can go in and buy anything that you
4 need.

5 So in 2024, Magnolia House opened the
6 fully-functioning -- the first fully-functioning
7 Family Justice Center, now recognized as the most
8 rural justice center in America. Every single day
9 we work with victims of domestic violence, sexual
10 assault, human trafficking, elder abuse, and with
11 families trying to rebuild their lives from the
12 ground up.

13 And for those survivors every monthly bill
14 matters. Affordable, dependable energy is one part
15 of whether they can rebuild their lives and become
16 sustainable on their own. In our shelter, in our
17 outreach offices, in my Family Justice Center and
18 in our home -- in homes victims move into, reliable
19 services is not a luxury. It is safety, it is
20 stability, and it is a peace of mind.

21 But I'm here this morning to speak on a
22 different reason because it meant a lot. I'm here
23 because I have seen firsthand what happens when a
24 corporation chooses -- they chose to be more than a
25 utility provider in our community and become a true

1 community partner.

2 Georgia Power was that partner, long before
3 the Family Justice Center was a statewide movement,
4 as it is now, long before I got to help with House
5 Bill 1283 this session to pass in the House and the
6 Senate to come -- become the fourth bill in the
7 nation to formally recognize family justice centers
8 into law, as soon as the governor signs it.

9 Georgia Power was already investing in that
10 vision. They provided seed funding for all three
11 Family Justice Centers in Georgia, which was
12 Waycross, Macon, and Cobb. And that model, when it
13 was still new, it was still a vision, there was
14 still uncertainty, and it was still just one of my
15 dreams. And because respected partners like
16 Georgia Power believed in us and a vision that
17 nobody else understood, I was able to go out and
18 raise another almost \$3 million to pay off my
19 center in Waycross because of Georgia Power's first
20 seed money, to be able to let the concept become a
21 reality in Georgia.

22 Macon is working on theirs right now to build
23 their new facility, and so are other people. That
24 early investment mattered to us, but it also
25 mattered to the partners that wanted to invest in

1 us when they saw that it mattered to Georgia Power,
2 because in rural south Georgia resources do not
3 come easily. And -- and we need people like
4 Georgia Power and their corporations to be able to
5 believe in our vision and believe in victim
6 services.

7 So instead of people having to go from place
8 to place, now they're under one roof, and they
9 are -- they find law enforcement, advocacy, legal
10 services and counseling and support with dignity,
11 with coordination. And for that, we'll always be
12 grateful for Georgia Power.

13 CHAIRMAN SHAW: Thank you.

14 MS. GIRTMAN: Thank you.

15 CHAIRMAN SHAW: Have a safe trip back home.

16 Mr. Frank Bove, followed by Gabe Chatham.

17 Good morning. How are you doing?

18 MR. BOVE: Okay. How are you doing?

19 CHAIRMAN SHAW: Good.

20 MR. BOVE: Okay. My name is Dr. Frank Bove.
21 I'm a retired CDC epidemiologist.

22 Today's hearing concerns Georgia Power's fuel
23 costs, but it should also consider who pays them.
24 Public Service Commission should stop giving
25 Georgia Power a blank check for fuel costs, forcing

1 customers who are already financially stretched to
2 the breaking point to bear the costs and risks of
3 the utility's poor decisions.

4 Georgia Power customers are facing an
5 affordability crisis. Since the start of the Iran
6 war, gasoline prices have risen by about 50 percent
7 in Georgia. The cost of groceries, housing, and
8 health care has increased. The majority of
9 families are living paycheck to paycheck. Rising
10 electricity bills are adding to this strain.

11 In 2025 alone, nearly 274,000 households,
12 which is about 11 percent of Georgia Power's
13 customers, were disconnected. Overall, customers
14 ended 2025 behind on their bills by more than
15 \$111 million.

16 Meanwhile, Georgia Power and its parent
17 company are doing well financially. Southern
18 Company's CEO was the nation's second-highest paid
19 utility executive in 2025, earning in one year what
20 the average Georgia worker would need more than 400
21 years to match.

22 Georgia Power reported \$628 million in
23 profits in the first quarter of 2026, an increase
24 of 5.4 percent over the previous year. Customers
25 are currently responsible for 100 percent of the

1 fuel costs, and those costs are expected to rise
2 significantly. Georgia Power relies heavily on
3 natural gas and coal, leaving customers exposed to
4 volatile fuel prices.

5 Before the Iran war, the utility projected a
6 25 percent increase in fuel costs for 2026 through
7 2028. That estimate now appears low. The Energy
8 Information Administration recently reported that
9 natural gas prices in January 2026 were 69 percent
10 higher compared to January 2025. With disruptions
11 to global energy supply chains due to the Iran War
12 and increased U.S. LNG exports and growing demand
13 from data centers. Natural gas prices will
14 continue to rise and skyrocketing diesel prices
15 will drive up coal transportation costs.

16 Georgia Power can reduce fuel costs by
17 relying more on clean energy, battery storage and
18 demand-side resources. But since its customers are
19 on the hook for 100 percent of the fuel costs, the
20 utility has no incentive to reduce these costs.
21 This is a textbook example of moral hazard where
22 one party makes the decisions while another party
23 bears the consequences.

24 The PSC can minimize this moral hazard and
25 encourage Georgia Power to reduce fuel costs by

1 adopting a fuel cost-sharing policy requiring the
2 utility to put some skin in the game and pay a
3 sufficient percentage of the fuel cost.

4 Commissions in nine states have adopted fuel
5 cost sharing. The PSC should require Georgia Power
6 to include a fuel cost line item on monthly bills,
7 so that customers know what they are paying for,
8 and Georgia Power's request to increase the interim
9 fuel rider threshold should be denied to maintain
10 timely monitoring of any fuel cost changes.

11 Finally, the PSC should push Georgia Power to
12 prioritize low cost and cost-stable, non-fuel
13 options for energy supply.

14 Thank you.

15 CHAIRMAN SHAW: Thank you, Doctor.

16 All right. Gabe Chatham followed by Carrie
17 K-E-O -- Keogh.

18 Hey, good morning.

19 MR. CHATHAM: Yes, sir. Good morning,
20 Mr. Chairman and Commissioners. My name is Gabe
21 Chatham, and I represent Chatham Built Homes,
22 third-generation homebuilder here in, really, the
23 north Atlanta area. My granddad grew up as a
24 sharecropper in northwest Fulton, and after World
25 War II came back and met my grandmother. And so he

1 started -- we had a little pig farm just outside of
2 town. It's a little area called Buckhead, began to
3 build a home for him and my grandmother and
4 realized there's a business here. So here we are,
5 77 years later, and honored to be still in this
6 industry.

7 And for us, you know, there's really new
8 opportunities, and so we serve in various roles.
9 This year I've been able to serve as president of
10 the state Home Builders Association. And so, you
11 know, one thing I've learned from my dad and my
12 granddad is, you know, in our business they can
13 have some good days and some bad days, you know,
14 trying to find stability is especially challenging.

15 And so when we see that in our commodity
16 prices, we see that in land prices, that's a
17 challenge. But if we can find consistency in
18 something like energy, you know, it's a big help to
19 our builders across the state, in fact, our friend,
20 Mark Ivey just shared a minute ago.

21 You know, from a builder's standpoint, you're
22 trying to find some stability. You're trying to
23 find confidence. And so confidence, when we're
24 trying to figure out what's the next development
25 and how do we develop it, how do we work with

1 buyers to create the products and create the
2 package that works for them, and the confidence
3 that the environment that we're building in has
4 some level of stability.

5 We're also heavily in the brokerage business,
6 and we see now the first-time homebuyer age is
7 nearing 40, so we realize so many people have been
8 kept from home ownership in large part because it's
9 not attainable. So when there's any portion of
10 that equation that's attainable, we're certainly
11 appreciative to that.

12 So that's why this three-year rate freeze has
13 been so valuable, so important in our industry.
14 And it's created some level of consistency in that
15 process that helps us deliver on the communities
16 and the homes that we're planning across the state.

17 And certainly when it relates to fuel cost,
18 we see in all our commodities, sometimes things go
19 up, things go down, but things go up. We recognize
20 the prices go up. But it's also great that we can
21 capture some of that and value when those prices go
22 down. And so that sends a great signal to those
23 folks that we're building for in the communities
24 that we're trying to support through housing.

25 And whether you're a first-time buyer,

1 last-time buyer, or even renting, you love some
2 sense of stability as to where that price is --
3 pricing is. And when it comes down, we are able
4 to -- to be able to appreciate some of that -- some
5 of that drop in price.

6 And so, you know, trust in our business,
7 trying to be consistent over the generations that
8 we've been in business and also being able to
9 support our home builders across the state. We see
10 so much value here because it reinforces
11 predictability. It supports the confidence in our
12 market. It certainly helps as we attract new
13 businesses and try to support those who are serving
14 our state, especially, in many cases, the first
15 responders that -- and those that support our
16 communities.

17 So with that, certainly appreciative of your
18 time. Thanks for all you do to serve our state.

19 CHAIRMAN SHAW: Thanks for taking the time to
20 be with us, Mr. Chatham.

21 MR. CHATHAM: Yes, sir.

22 Ms. Carrie Keogh followed by Jean Millkey.

23 Hey, good morning.

24 MS. KEOGH: Good morning, Commissioners.

25 CHAIRMAN SHAW: I'm so sorry about that.

1 MS. KEOGH: It's okay. It's an Irish name.
2 Nobody knows how to pronounce it.

3 CHAIRMAN SHAW: How do you say it?

4 MS. KEOGH: Keogh.

5 CHAIRMAN SHAW: Keogh. Well, I was pretty
6 close.

7 MS. KEOGH: You were really close.

8 CHAIRMAN SHAW: Yeah.

9 MS. KEOGH: Good morning, Commissioners. My
10 name is Carrie Keogh. I'm a DeKalb County resident
11 and a Georgia Power customer.

12 I'm here because I believe Georgians deserve
13 an energy grid that's based on clean and reliable
14 energy with solar and batteries that help protect
15 us from the volatility of fossil fuels, in the
16 short term, and that provide clean, safe, and
17 renewable energy for the long term, without
18 compromising our health or literally the
19 habitability of our planet.

20 Fossil fuel markets are obviously extremely
21 volatile, and because Georgia Power passes on
22 100 percent of the fuel cost to customers like me,
23 we are exposed to all the risks in price hikes and
24 forecasting mistakes. While -- while Georgia Power
25 is reducing the fuel charge that -- that it put on

1 two years ago, they're only reducing it by a small
2 portion. So of the \$16-per-month jump that I
3 experienced a couple of years ago, it's only going
4 down by, I think, what, \$4 from this particular
5 instance of reducing the surcharge.

6 So I have three particular requests for the
7 Commission today. In addition to being a major
8 contributor to climate change, natural gas is one
9 of the most volatile fossil fuels available.
10 There's evidence from prior years' testimony and
11 precedent from other states that you, the
12 Commission, can require Georgia Power to absorb a
13 portion of fuel costs instead of letting them pass
14 100 percent of those costs onto us.

15 Please use your authority to require Georgia
16 Power to absorb a small portion of fuel costs so
17 that they can make more just decisions about fuels.
18 Hopefully, in addition to helping protect customers
19 from reckless decision making, having some skin in
20 the game for the cost of volatile fossil fuels will
21 help them comprehend the economic sense of
22 renewable energy.

23 Second, I understand the PSC staff
24 recommended terminating the natural gas hedging
25 program because it doesn't actually protect

1 customers and instead it has cost us millions of
2 dollars. Please do not allow Georgia Power to
3 expand the natural gas hedging program or extend
4 related contracts. All this does is shift
5 additional costs and risk to customers and keeps us
6 saddled with more years of fossil fuel dependence.

7 And finally, I want to ask the Commission to
8 closely examine the way that fuel costs are
9 allocated between different categories of customers
10 that Georgia Power serves. So in particular, I'm
11 asking what the new large load customers, i.e., the
12 data centers, what are they being charged for fuel,
13 and how has that cost changed or not changed, since
14 whatever the RTP pricing was that they were
15 probably originally offered to get them in the
16 door.

17 Please look closely at the RTP rates and
18 assess whether they are still being applied to data
19 centers. Data centers don't need a sweetheart
20 economic deal or development rate. Please examine
21 whether they're paying their fair share of costs.

22 I hope the Commission will work towards
23 greater transparency and oversight of Georgia
24 Power, and I hope to also see a date sometime
25 posted for the next fuel docket.

1 Thank you very much for your time.

2 CHAIRMAN SHAW: Thank you.

3 Jean Millkey, followed by Eric Mintz.

4 IT had reached out. They're having some
5 issues with hearing everyone, so feel free to bring
6 that mic a little closer. So we want to make sure
7 everyone online can hear you.

8 MS. MILLKEY: Does this work?

9 CHAIRMAN SHAW: That's perfect. Thank you.

10 MS. MILLKEY: Thank you, Commissioners, for
11 allowing us to speak today.

12 I am here because I am angry. I do not have
13 a choice in energy companies unless I move. I do
14 not have a choice in the type of energy that powers
15 my residence. And Georgia Power treats us
16 residential customers as if we are blindly eager to
17 bear the costs of their poor decisions.

18 Georgia Power spends a lot of money, money
19 that we pay on marketing, trying to convince us
20 that their priorities include, according to their
21 web page, safety first, intentional inclusion,
22 acting with integrity and superior performance.

23 We, the customers, have seen little evidence
24 of any of these priorities. Instead, we see that
25 they prioritize profits for their shareholders and

1 their executives, and they are doing so again in
2 their fuel cost recovery request.

3 Georgia Power thinks we, its customers, do
4 not realize that customers are being forced to pay
5 100 percent of the fuel cost risks. Georgia Power
6 is -- we do not -- they do not realize that -- we
7 realize that Georgia Power is seeking billions in
8 fuel cost recovery without a credible plan to
9 reduce volatility or lower costs. We are being
10 asked to pay hundreds of millions in
11 under-recovered costs caused by Georgia Power's
12 decisions and forecasting errors, and Georgia
13 Power's fuel cost model removes any incentive to
14 control costs or make better long-term decisions.

15 When a utility can pass 100 percent of fuel
16 costs onto customers, it has little motivation to
17 minimize risk. Georgia Power wants to increase
18 this income stream by hedging, by expanding their
19 hedging and extending their contracts, even though
20 the PSC staff warns that this expansion could
21 significantly increase the financial risk for
22 customers. Again, the burden would fall on
23 customers, and we're stuck. We don't have choices.

24 Right now, if fuel prices spike, we, the
25 customers, pay. If the projections are wrong, we

1 pay. If poor decisions or project delays drive up
2 costs, we pay. If the new expanded capacity
3 projects aren't needed in the end for energy
4 generation, we still pay for that added capacity.

5 Georgia Power avoids financial risk, and when
6 a company is allowed to pass along all costs
7 without consequence, it loses the incentive to
8 control those costs. There is no pressure to
9 forecast accurately.

10 Please, Commissioners, we've recently
11 witnessed the lack of concern about Georgia Power's
12 lack of accountability by the state legislature.
13 So please help us hold Georgia Power accountable.
14 Protect the customers who have no choice. Shifting
15 the risks onto Georgia families while shielding the
16 company from its own bad decisions is wrong. I am
17 asking you to not approve the threshold increase,
18 to demand transparency, and to hold Georgia
19 accountable.

20 Thank you.

21 CHAIRMAN SHAW: Thank you.

22 Eric Mintz, followed by Rochelle Dennis.

23 Good morning.

24 MR. MINTZ: Good morning, Commissioners. My
25 name is Eric Mintz. I'm a Georgia voter, a retired

1 physician and an epidemiologist.

2 In the first quarter of this year, profits of
3 Georgia Power's parent company, the Southern
4 Company, were \$1.3 billion, up by nearly 2 percent
5 from last year. Southern Company, which owns
6 Southern Gas, Southern Natural Gas, and Atlanta Gas
7 Light, does profit from the sale and the
8 transportation of methane gas.

9 The recently approved IRP for an additional
10 ten gigawatts of capacity, mostly generated by new
11 or expanded gas-burning power plants, will cost
12 Georgia Power customers billions of dollars that
13 will show up in Southern Company's future profits.

14 Your job is to ensure that Georgians have
15 affordable, safe, and reliable electricity.
16 Ensuring that Georgia Power and the Southern
17 Company has reliable outside -- outsized profits is
18 not your job.

19 We're here today to discuss fuel recovery
20 costs for the gas that Georgia Power burned over
21 the last three years. We are not here to talk
22 about the recovery costs for the sunlight captured
23 by solar panels that Georgia Power used to generate
24 electricity. Sunlight is free. It always has
25 been. It always will be.

1 Affordability demands a transition from
2 fossil fuel burning to fuel-free energy. Fossil
3 fuel prices are highly volatile, and dependent on
4 fossil fuels is risky. Georgia Power customers
5 have paid for the price hikes in fossil fuels from
6 the Russian war on Ukraine, and will pay for the
7 hike in fossil fuel prices from the American war on
8 Iran.

9 Georgia Power does not care about fuel price
10 hikes because they don't pay them. We do. The
11 transition away from fossil fuels to fuel-free
12 energy demands a fuel cost-sharing agreement with
13 Georgia Power.

14 Burning fossil fuels is dangerous to human
15 health directly and through the effects it has on
16 our climate. Those effects include more frequent
17 and more severe hurricanes. This is an issue about
18 safety and about the cost customers must pay for
19 storm damages.

20 The amount of fossil fuels on Earth is
21 finite. The more we burn, the less we have. The
22 less we have, the more they cost. Our sun has been
23 shining for 5 billion years and has 5 billion years
24 left to burn. This is radically more reliable than
25 fossil fuels. Many states and many countries are

1 transitioning to fuel-free solar power. Georgia
2 should not be left behind.

3 Thank you.

4 CHAIRMAN SHAW: Thank you.

5 Rochelle Dennis, followed by Angelia
6 Pressley.

7 MS. DENNIS: Good morning.

8 CHAIRMAN SHAW: Good morning. How are you?

9 MS. DENNIS: I'm well. How are you?

10 CHAIRMAN SHAW: Good.

11 MS. DENNIS: I'm Rochelle Dennis, and I serve
12 as the economic development director for the City
13 of Forest Park, and I'm here to express our support
14 for Georgia Power's fuel cost recovery filing
15 FCR-27, currently before you, the Georgia Public
16 Service Commission.

17 The City of Forest Park represents a diverse
18 community of more than 19,000 residents, along with
19 a strong base of local businesses and critical
20 economic development interests. Affordable and
21 reliable electric service is essential to the
22 people and operations we support as energy costs
23 directly impact daily operations, long-term
24 planning, and overall economic stability.

25 Georgia Power's fuel cost recovery process is

1 a longstanding and transparent mechanism that
2 allows the company to recover the actual cost of
3 fuel used to generate electricity.

4 Importantly, Georgia Power does not earn a
5 profit on fuel costs, and all fuel expenses are
6 subject to review and approval by the Commission to
7 ensure they are responsible and prudent. Fuel
8 prices fluctuate based on market conditions, beyond
9 the control of individual customers or utilities.
10 The fuel costs recovery framework provided --
11 provides a responsible way to reflect those changes
12 without permanently embedding volatile fuel
13 expenses into base rates. This approach promotes
14 transparency, fairness, and stability for
15 customers. Reliable electric service is a
16 foundational element of Georgia's economy and
17 quality of life.

18 We appreciate the Commission's careful
19 oversight in balancing affordability with
20 reliability, while ensuring costs are reviewed
21 through a public and regulated process. For these
22 reasons, the City of Forest Park respectfully
23 supports Georgia Power Company's fuel cost recovery
24 filing.

25 Thank you very much.

1 CHAIRMAN SHAW: Thank you.

2 Angelia Pressley, followed by Aidyn Levin.

3 Hey. Good morning.

4 MS. PRESSLEY: Good morning.

5 Good morning, Commissioners. I'm Angelia
6 Pressley, a university professor.

7 While you are planning to balance our fuel
8 recovery and storm charges to avoid increasing
9 rates, today I'm here to express my deep opposition
10 to the continued cycle of hedging and fuel cost
11 recovery requests that place an unsustainable
12 burden on Georgia's families.

13 We are in a crisis, and the take-take dynamic
14 of utility monopoly is forcing residents to make
15 impossible choices. The reality for everyday
16 Georgians is the choice between heating and eating,
17 because we still have cold days right now.

18 I personally know neighbors opting to stay in
19 the cold just to afford food. This is not limited
20 to those in poverty. Conservative single
21 individuals and families are reporting combined
22 utility bills as high as \$1,500 a month, while
23 incomes are remaining stagnant and people are out
24 of work.

25 These costs are a direct driver of rising

1 homelessness in our communities, and, boy, do I
2 know a lot of them. The current path of passing
3 all market risks and pressures onto ratepayers has
4 failed. While the PSC has discussed the base rate
5 freeze, the fuel recovery costs, other riders
6 continue to drain households. Hedging must not be
7 a tool used only to protect the company's bottom
8 line, while ratepayers remain at risk for every
9 fluctuation in the economy.

10 I'm calling on this Commission to move beyond
11 the reactive rate cases and mandate a comprehensive
12 study of ratepayer housing and the grid. We need a
13 proactive, creative plan to repair and reinvest in
14 our communities. Focusing on local generation and
15 efficiency that actually lowers bills rather than
16 shifting how they are collected is what is needed
17 today.

18 I urge this Commission to use every tool to
19 lower bills, nuclear credits, whatever it is, and
20 reject any further shifting of fuel risks to the
21 public and to freeze all riders until a
22 community-centered reinvestment plan is
23 established. This system, unfortunately, is rigged
24 against the consumer, and the stress is no longer
25 sustainable.

1 Thank you for your time, and please remember
2 the people behind these dockets.

3 CHAIRMAN SHAW: Thank you.

4 Aidyn Levin, followed by Thomas Lynch.

5 Hey. Good morning.

6 MS. LEVIN: Good morning. My name is Aidyn
7 Levin, and I'm here representing the Georgia Public
8 Interest Research Group.

9 Georgia PIRG is a nonpartisan, statewide
10 consumer protection organization. Whether it's
11 protecting Georgia's kids from unsafe AI toys or
12 fighting for Georgians' right to repair the
13 consumer electronics they bought and paid for, we
14 work to stand up for the safety and health of
15 Georgians.

16 I want to begin by saying that Georgia
17 Power's messaging is that costs are going down, but
18 here's the reality: Fuel costs are going up. Gas
19 prices are highly volatile, which is what got us to
20 this point, due to the spike in fuel prices after
21 Russia's invasion of Ukraine.

22 This volatility is bad for customers who have
23 to pay all of the fuel costs, and yet Georgia Power
24 is increasingly reliant on gas. Georgia PIRG
25 commissioned a study that showed what that

1 volatility might mean for customers in the future,
2 and here's a shocking statistic: Because Georgia
3 Power is increasing its reliance on gas by 2035,
4 the average customer could be paying an extra \$125
5 in annual fuel costs because of gas price
6 volatility.

7 That leads me to our request for you.
8 Georgia PIRG believes that there needs to be
9 increased transparency and accountability around
10 fuel costs. But in this docket, by seeking to
11 increase the interim fuel cost recovery mechanisms
12 trigger from \$200 million to \$300 million, Georgia
13 Power is trying to decrease transparency.

14 I urge the Commission to reject Georgia
15 Power's request to raise the threshold. Georgia
16 PIRG also supports the request of intervenors from
17 Southface and GIPL to reduce the maximum amount by
18 which fuel rates can be adjusted during a fuel cost
19 recovery cycle from 40 percent to 15 percent.

20 In that vein, we urge the Commission to
21 require Georgia Power to add a fuel cost line item
22 on all customer bills. Customers deserve to know
23 how much of their electric bill comes from fuel
24 costs.

25 Georgia PIRG is also requesting a fuel cost

1 sharing mechanism be implemented for Georgia Power.
2 A fuel cost sharing mechanism as described in
3 Michael Goggin's testimony on behalf of Southern
4 Alliance for Clean Energy, Sierra Club and NRDC,
5 would incentivize Georgia Power to reduce their
6 exposure to fuel cost volatility.

7 While I know that you might have limited
8 ability to address this issue within this docket, I
9 would be remiss if I didn't point out that we need
10 to invest in energy efficiency and electricity
11 sources that do not have fuel costs, including
12 solar, wind, and battery storage. Why should we,
13 Georgia Power's customers, be on the hook for
14 millions of dollars in fuel costs when Georgia
15 Power could be using options that don't have fuel
16 costs?

17 Thank you for the opportunity to speak.

18 CHAIRMAN SHAW: Thank you.

19 Thomas Lynch, followed by Karen Davenport.

20 Hey. Good morning.

21 MR. LYNCH: Good morning. Thanks for your
22 time.

23 I'm Thomas Lynch, and a Georgia voter. I'm a
24 retired PhD scientist, and I understand that
25 Georgia Power is planning on building more

1 methane-burning power plants, primarily to power
2 the ever-increasing number of data centers.

3 I find this odd, since Georgia Power has
4 plenty of experience installing and operating solar
5 farms, including the recently approved one-gigawatt
6 expansion. Solar and battery storage provide less
7 expensive electricity and are faster to install
8 than building new methane-burning power plants.

9 Further, with methane-burning power plants,
10 you have to continuously buy and feed them methane
11 24 hours a day, year after year, decade after
12 decade. While, in contrast, once you install
13 solar, it produces electricity. No fuel needed,
14 just the sun.

15 So it's timely that today we're talking about
16 fuel costs on everyone's electricity bills.
17 Remember, there are no fuel costs with solar power.

18 Additionally, if Georgia Power simply charges
19 data centers for their new methane-burning power
20 plants, instead of charging this to their
21 customers, this ignores the fact that these new
22 plants would spew millions of tons of carbon
23 dioxide into the air, leading to global warming,
24 which gives rise to more frequent and intense
25 hurricanes, like Hurricane Helene, that cost

1 Georgians over \$6 billion and 37 deaths.

2 And, coincidentally, I understand this is a
3 topic for next week's hearings.

4 Our increased global warming has also led to
5 wildfires worldwide, like our current Pineland Road
6 fire in south Georgia that has already burned
7 37,000 acres.

8 If Georgia Power truly cares about their
9 customers, the choice is clear. Any new power for
10 data centers needs to come from solar. To do this,
11 Georgia Power can install new, even more solar
12 farms than currently planned. Georgia Power can
13 install solar panels over farmland and grazing
14 land, also known as agrivoltaics. This reduces
15 land-use conflicts and boosts farm income.

16 Further still, Georgia Power could expand
17 their community solar programs using the resulting
18 power savings for the data centers.

19 In summary, I commend Georgia Power's
20 infusion of solar power into their mix. For
21 building more methane-burning power plants now, to
22 me, is unconscionable and, in fact, immoral.

23 Remember, the target here is net zero
24 greenhouse emissions, and we're nowhere near where
25 we need to be. So I'm simply asking this

1 Commission to insist that Georgia Power install
2 only solar power for any future power expansions.

3 Again, thanks for your time.

4 CHAIRMAN SHAW: Thank you, sir.

5 Karen Davenport. Good morning.

6 MS. DAVENPORT: Good morning. I'm Karen
7 Davenport. I'm a citizen from DeKalb County.

8 Commissioners, I am here today to address a
9 fundamental -- fundamental failure in the way
10 energy is priced in Georgia. Right now, if fuel
11 prices spike, the customer pays. If the company's
12 projections are wrong, the customer pays. If poor
13 decisions or project delays drive up costs, the
14 customer pays.

15 Under this system, Georgia Power faces
16 virtually zero cost or zero financial risk. When a
17 company is allowed to pass along every single
18 dollar of cost without consequences, it loses the
19 incentive to control those costs. There is no
20 pressure to forecast accurately and no urgency to
21 act when balances begin to spiral.

22 Georgia Power claims they don't earn a return
23 on fuel costs. That is -- that it is a straight
24 pass-through. This is deeply not true. While
25 Georgia Power Company might not profit, its parent

1 company, Southern Company, does -- certainly does.

2 The return is earned by Southern Company
3 Services, which markets the gas. It's earned by
4 Southern Power, which sells the electricity back to
5 Georgia Power. It's earned by the Southern Natural
6 Gas Pipeline, which transports that gas.

7 To tell the public that no one is profiting
8 from these fuel costs is a shell game designed to
9 hide the fact that Georgia families are padding the
10 bottom line of a multibillion dollar corporate
11 empire. We are seeing the results of this lack of
12 accountability right now. Customers are being told
13 they owe hundreds of millions in under-recovered
14 fuel costs.

15 These balances did not appear overnight.
16 They grew while the company watched and waited.
17 Georgia Power allowed these costs to blow past key
18 thresholds without making adjustments. They chose
19 debt and interest over proactive management, and
20 now they are passing that on to us.

21 Even worse, they are asking to raise the
22 threshold, actually, from 200 million to
23 300 million so they can let more debt pile up
24 before they are forced to deal with it.

25 At the same time, they are trying to sneak

1 internal administrative expenses into fuel costs
2 that should be handled through normal business
3 operations.

4 I'm asking the Commission to please check on
5 monopoly profit seeking. Please protect the
6 customers who have no choice in their utility
7 provider. Shifting all the risk onto Georgia
8 families while shielding the company from its own
9 bad decisions is wrong. I'm asking you to reject a
10 threshold increase and demand transparency in the
11 Southern Company supply chain. And please stop
12 this pattern of unaccountable spending.

13 Thank you.

14 CHAIRMAN SHAW: Thank you, Ms. Davenport.

15 All right. That is the end of the sign-up
16 sheet. Was there anyone else that came in
17 afterwards that didn't get to sign up that wanted
18 to address the Commission?

19 (No response.)

20 All right. Well, we will take a quick -- do
21 y'all need just a couple of minutes to get your
22 panel ready? Okay. We'll just break for two or
23 three minutes. And when -- as soon as the panel is
24 ready, we'll proceed.

25 And thank you to all the public witnesses for

1 taking the time to be with us this morning. You're
2 welcome to stick around and the hearing will begin.
3 We're going to keep things rolling.

4 (Whereupon a break was taken.)

5 CHAIRMAN SHAW: All right. Are y'all ready?
6 We will move on.

7 Were there any housekeeping matters to take
8 up before we move on to the witness panels?

9 (No response.)

10 Okay. Hearing none, Georgia Power, if you
11 want to call up your first witness panel and swear
12 them in.

13 MS. PRYOR: Good morning, Commissioners.
14 Allison Pryor for Georgia Power Company. At this
15 time, I'd like to call Georgia Power's panel of
16 witnesses on direct, Mr. Adam Houston and
17 Mr. Matthew Berrigan, to the stand.

18 Thank you, gentlemen.

19 I'll note for the record that the notice of
20 publication was filed for this proceeding as
21 required by the Commission's rules.

22 Mr. Houston and Mr. Berrigan, please raise
23 your right hand.

24 Thereupon,

25 ADAM DUNCAN HOUSTON,
~~MATTHEW S. BERRIGAN,~~

1 having been duly sworn, testified as follows:

2 DIRECT EXAMINATION

3 BY MS. PRYOR:

4 Q. Mr. Houston, please state your full name,
5 your employer, and your responsibilities for the record.

6 A. (Witness Houston) Yeah. Adam Duncan
7 Houston, Georgia Power Company. I oversee the financial
8 reporting and accounting and also the regulatory
9 accounting functions.

10 Q. And, Mr. Berrigan, would you do the same?

11 A. (Witness Berrigan) Matthew Berrigan, Georgia
12 Power Company. Assistant comptroller and I have primary
13 responsibility for regulatory accounting.

14 Q. Thank you.

15 And, Mr. Houston, on February 17th of this
16 year, in support of Georgia Power's application for a
17 change in fuel rates, did you prefile or cause to be
18 prefiled 26 pages of direct testimony in
19 question-and-answer format?

20 A. (Witness Houston) Yes.

21 Q. Along with your direct testimony, did you
22 also prefile seven exhibits identified as ADH/MSB 1
23 through 7, plus the historical minimum filing requirements
24 and the projected minimum filing requirements?

25 A. (Witness Houston) Yes.

1 Q. Mr. Houston, do Exhibits 1, 2, 3, and 7, as
2 well as the historical and projected minimum filing
3 requirements contain certain information that was filed
4 under the trade secret rules of the Georgia Public Service
5 Commission?

6 A. (Witness Houston) Yes.

7 Q. And did you separately file a trade secret
8 version and a public disclosure version of Exhibits 1, 2,
9 3, 7, and the historical and projected minimum filing
10 requirements?

11 A. (Witness Houston) Yes.

12 Q. Were these documents prepared under your
13 supervision and direction?

14 A. (Witness Houston) Yes.

15 VICE CHAIRMAN MCDONALD: Matthew, would you
16 get closer to that microphone, please. Thank you.

17 MR. HOUSTON: How's that? Much better?

18 VICE CHAIRMAN MCDONALD: Thanks.

19 MS. PRYOR: Chairman Shaw, I would like to
20 identify the prefiled exhibits as follows: Public
21 disclosure Exhibit ADH/MSB 1 as Hearing Exhibit
22 Georgia Power 1 and the trade secret version as
23 GPC 2.

24 Public disclosure Exhibit ADH/MSB 2 as
25 Hearing Exhibit GPC 3 and trade secret version as

1 GPC 4.

2 Public disclosure Exhibit ADH/MSB 3 as
3 Hearing Exhibit GPC 5 and the trade secret version
4 as GPC 6.

5 Exhibit ADH/MSB 4 as GPC 7. Exhibit
6 ADH/MSB 5 as GPC 8.

7 Exhibit ADH/MSB 6 as GPC 9. Public
8 disclosure exhibit ADH/MSB 7 as Hearing Exhibit
9 GPC 10, and the trade secret version as GPC 11.

10 The public disclosure version of the
11 historical minimum filing requirements as GPC 12
12 and the trade secret version as GPC 13.

13 And the public disclosure version of the
14 projected minimum filing requirements as GPC 14 and
15 the trade secret version as GPC 15.

16 CHAIRMAN SHAW: So marked.

17 (The documents referred to were marked for
18 identification as GPC Exhibits 1 through 15.)

19 BY MS. PRYOR:

20 Q. Mr. Houston, on March 17th, did you file or
21 cause to be filed an errata, both trade secret and public
22 disclosure versions, to the historical Minimum Filing
23 Requirement 7.3?

24 A. (Witness Houston) Yes.

25 Q. Was the new version of MFRH-7.3 prepared

1 under your supervision and direction?

2 A. (Witness Houston) It was.

3 MS. PRYOR: Chairman Shaw, I ask that the
4 public disclosure version of the errata be labeled
5 as GPC 16 and the trade secret errata be labeled as
6 GPC 17.

7 CHAIRMAN SHAW: So marked.

8 (The documents referred to was marked for
9 identification as GPC Exhibit 16 and 17.)

10 BY MS. PRYOR:

11 Q. On April 30th, did you file or cause to be
12 prefiled a second errata with both trade secret and public
13 disclosure versions of the projected Minimum Filing
14 Requirement 1?

15 A. (Witness Houston) Yes.

16 Q. Was the new version of MFRP 1 prepared under
17 your supervision and direction?

18 A. (Witness Houston) Yes.

19 MS. PRYOR: Chairman Shaw, I ask that the
20 public disclosure version of the second errata be
21 labeled as GPC 18, trade secret errata be labeled
22 as GPC 19.

23 CHAIRMAN SHAW: So marked.

24 (The documents referred to was marked for
25 identification as GPC Exhibit 18 and 19.)

1 BY MS. PRYOR:

2 Q. Mr. Houston, did either errata make a
3 correction to your testimony?

4 A. (Witness Houston) Yes.

5 Q. Was that correction specified in the errata?

6 A. (Witness Houston) Yes, it was.

7 Q. And did the correction in the errata impact
8 the under-recovered fuel balance or change the company's
9 recommendations regarding fuel rates in any way?

10 A. (Witness Houston) Yes, it did. The errata
11 was for a reduction of some capacity expenses to the
12 extent of \$3.9 million. So it reduced the -- the request
13 by 3.9 million.

14 Q. Thank you. On April 10th, did the company
15 file updates to the historical MFRs 2, 4.1, 4.2, 10, 14,
16 and 15 to update them for the actuals incurred for the
17 months of January and February 2026, as required by
18 Commission rules?

19 A. (Witness Houston) Yes.

20 Q. And on May 1st, 2026, did the company file
21 updates to the same historical MFRs to update them for
22 actuals incurred for the month of March 2026?

23 A. (Witness Houston) Yes.

24 Q. Considering the corrections made through the
25 two errata filings and the updates to the historical MFRs,

1 are there any other corrections you need to make to the
2 application or to Georgia Power's Exhibits 1 through 19?

3 A. (Witness Houston) No.

4 Q. Are they true and correct, to the best of
5 your knowledge?

6 A. (Witness Houston) Yes, they are.

7 Q. Regarding your direct testimony, if I were to
8 ask you the same questions today under oath, would your
9 answers be the same as are set forth in that prefiled
10 direct testimony as updated by the errata?

11 A. (Witness Houston) Yes.

12 MS. PRYOR: Chairman Shaw, the court reporter
13 was previously given a copy of the panel's prefiled
14 direct testimony and I now ask that that direct
15 testimony of Mr. Houston and Mr. Berrigan be copied
16 into the record as if given here today.

17 CHAIRMAN SHAW: Noted. So marked.

18 (Whereupon, the prefiled direct testimony
19 and errata of Adam Duncan Houston and Matthew S.
20 Berrigan follows:)

DIRECT TESTIMONY OF
ADAM D. HOUSTON AND MATTHEW S. BERRIGAN
ON BEHALF OF GEORGIA POWER COMPANY
IN SUPPORT OF GEORGIA POWER’S FUEL COST RECOVERY (FCR-27)
APPLICATION, GPSC DOCKET NO. 56765

I. INTRODUCTION

1 **Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

2 A. Adam D. Houston. I am the Vice President and Comptroller for Georgia Power
3 Company (“Georgia Power” or the “Company”). My business address is 241 Ralph
4 McGill Boulevard, Atlanta, Georgia 30308.

5 A. Matthew S. Berrigan. I am the Assistant Comptroller for Georgia Power. My
6 business address is 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

7 **Q. MR. HOUSTON, PLEASE SUMMARIZE YOUR EDUCATIONAL AND**
8 **PROFESSIONAL EXPERIENCE.**

9 A. I graduated from Victoria University of Wellington, New Zealand in 1995 with a
10 Bachelor of Commerce and Administration in Economics and Finance. I began my
11 professional accounting career with Arthur Andersen, LLP in Wellington as an
12 Associate performing audits for multinational and local clients. From 2002, I
13 worked for PricewaterhouseCoopers, LLP in Los Angeles and Chicago specializing
14 in Power and Utility audits across the United States, including Exelon utility
15 subsidiaries, PHI Holdings, and AGL Resources Inc. In 2017, I joined Southern
16 Power Company (“Southern Power”) as the Assistant Comptroller responsible for
17 accounting research, accounts payable, and internal controls and compliance. While
18 at Southern Power, I was also given responsibility for financial accounting and
19 reporting, and property accounting. In 2021, I joined Georgia Power as the
20 Assistant Comptroller responsible for financial accounting and reporting,

1 regulatory accounting (including fuel), and accounting research. In 2023, I was
2 promoted to Vice President and Comptroller of Georgia Power. I am a Chartered
3 Accountant member of the Chartered Accountants Australia and New Zealand.

4 **Q. MR. HOUSTON, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
5 **COMMISSION?**

6 A. Yes. I testified before the Commission in Georgia Power's 2022 Rate Case in
7 Docket No. 44280 and in the Company's Fuel Cost Recovery ("FCR") 26
8 proceeding in Docket No. 44902.

9 **Q. MR. BERRIGAN, PLEASE SUMMARIZE YOUR EDUCATIONAL AND**
10 **PROFESSIONAL EXPERIENCE.**

11 A. I graduated from the University of Georgia in 2002 with a Bachelor of Business
12 Administration and Accounting, as well as a Master of Accountancy. I began my
13 professional accounting career with Deloitte & Touche, LLP in Atlanta as an
14 auditor primarily serving Southern Company. In 2013, I joined SG Digital (a
15 Division of Scientific Games Corporation) as the Director of SEC Reporting and
16 Technical Accounting. In 2015, I joined AGL Resources, Inc. (now Southern
17 Company Gas) as the Assistant Comptroller responsible for accounting research,
18 SEC Reporting, and internal controls and compliance. While at Southern Company
19 Gas, I was also given responsibility for corporate accounting, affiliate transactions,
20 and consolidations. In 2023, I joined Georgia Power as the Assistant Comptroller
21 responsible for financial accounting and reporting, regulatory accounting
22 (including fuel), and accounting research. I am a Certified Public Accountant
23 licensed in Georgia.

24 **Q. MR. BERRIGAN, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE**
25 **GEORGIA PUBLIC SERVICE COMMISSION?**

26 A. Yes. I testified before the Commission in support of Georgia Power's Stipulation
27 to Extend the Alternate Rate Plan in Docket No. 44280.

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1 filing, the Company has also filed a Storm Damage Recovery Application. Taken
2 together, these filings will result in a reduction of customer bills by \$1.32 per month
3 for a typical residential customer.

4 Additionally, as a part of this filing, the Company recommends modifying the
5 Interim Fuel Recovery Mechanism (“IFR”) to better align the IFR threshold to the
6 magnitude of the total fuel expenses incurred by the Company on an annual basis.
7 This modification will provide greater rate stability for customers by allowing FCR
8 rates set in this filing to absorb natural fuel price volatility and normal fluctuations
9 in the fuel over- or under-recovery balances on a monthly basis.

10 Finally, the Company proposes to expand its natural gas hedging program by
11 increasing both the percentage of budgeted burn that may be hedged and the length
12 of the hedging window. This expansion is warranted given the projected growth in
13 natural gas burn in the Company’s budget. By enhancing the scope of the hedging
14 program, the Company will be better positioned to mitigate exposure to price
15 fluctuations and provide greater stability in fuel costs for the benefit of customers.

16 **Q. WHAT IS DRIVING THE NEED TO REDUCE THE COMPANY’S FUEL**
17 **RATES?**

18 A. The proposed decrease in fuel rates is primarily driven by the continued recovery
19 of \$2.2 billion of previously under-recovered fuel balance from FCR-26, as
20 expected, with the remaining balance at \$310 million as of December 2025. Based
21 on the 2026 Energy Budget included in this filing, virtually all the remaining
22 balance is expected to be collected by May 2026, prior to the implementation of the
23 new fuel rates on June 1, 2026.

24 This decrease is partially offset by the under-recovery of fuel expenses accumulated
25 since the FCR-26 rate went into effect on June 1, 2023, which is \$212 million as of
26 December 2025, and is projected to grow to \$300 million by May 31, 2026. The
27 FCR-26 under-recovery is primarily driven by higher levels of coal generation, and

actual natural gas prices that were lower than what was projected in Real-Time Pricing (“RTP”) revenues in the FCR-26 budget. In addition, there are increasing fuel expenses in the forecasted periods primarily driven by projected increase in natural gas prices compared to the natural gas price update incorporated for fuel rates in FCR-26 and the higher load requirement projected in the test period. We explain these factors in greater detail later in this testimony.

Even with these factors putting upward pressure on rates, the recovery of prior under-recovered fuel balance more than offsets these items and the result is a net decrease to customers of \$388 million on an annual basis, as shown in Exhibit___(ADH/MSB-7), Page 1. As a result, the Company seeks to adjust its fuel rates to recover its projected fuel costs for the FCR-27 test period as further described below.

III. THE PROPOSED FCR-27 RATES

Q. PLEASE DESCRIBE THE PROPOSED FCR-27 RATES AND THEIR IMPACT TO CUSTOMERS.

A. The seasonal, stratified rates proposed for FCR-27 (*see* Exhibit___(ADH/MSB-5), Pages 1 and 2) are set forth below in **Table 1**:

Table 1
(cents per kWh)

	Average Rate	Transmission	Primary	Secondary
Winter (Oct-May)	3.8368	3.7700	3.7965	3.8657
Summer (June-Sept)	3.7873	3.7214	3.7475	3.8158

The average winter FCR-27 rate represents a decrease of 0.4170 cents per kWh, to the current average winter FCR-26 rate of 4.2538. The average summer FCR-27

1 rate represents a decrease of 0.7660 cents per kWh to the current average summer
2 FCR-26 rate of 4.5533.

3 Based on the latest 2026 Energy Budget and considering a projected FCR-26 under-
4 recovered fuel balance of approximately \$300 million, the requested changes set
5 forth in this FCR-27 filing result in an average decrease in fuel rates of 12.6%. This
6 fuel rate change equates to a decrease of \$5.74 on the bill of the typical residential
7 customer using an average of 1,000 kWh per month.

8 **Q. WHAT IS THE BREAKDOWN OF RATES PROPOSED FOR FCR-27**
9 **BETWEEN PARTS A AND B?**

10 A. The seasonal, stratified rates proposed for FCR-27 for Parts A and B (*see*
11 Exhibit ___(ADH/MSB-5), Pages 1 and 2) are set forth below in **Table 2**:

Table 2
(cents per kWh)

Part A	Average Rate	Transmission	Primary	Secondary
Winter (Oct-May)	3.6953	3.6310	3.6565	3.7231
Summer (June-Sept)	3.6450	3.5816	3.6067	3.6725

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Part B	Average Rate	Transmission	Primary	Secondary
Winter (Oct-May)	0.1415	0.1390	0.1400	0.1426
Summer (June-Sept)	0.1423	0.1398	0.1408	0.1434

1 Part A represents the component of the fuel rate designed to recover future
2 projected costs as presented in this filing in the test period beginning with the
3 implementation of new rates effective June 1, 2026. Part B represents the
4 component of the fuel rate designed to recover over- or under-recovered fuel costs
5 since the current fuel rate went into effect on June 1, 2023, through the projected
6 period effective for the current rate, or May 31, 2026.

7 **Q. WHAT PERIOD IS THE COMPANY PROPOSING TO RECOVER THE**
8 **AMOUNT OF UNDER-RECOVERED FUEL SINCE FCR-26?**

9 A. The Company is proposing to recover the projected amount of \$300 million of fuel
10 under-recovered balance as of May 31, 2026, over a three-year period from June 1,
11 2026, through May 31, 2029.

12 **Q. WHEN DOES THE COMPANY PROPOSE TO IMPLEMENT THE NEW**
13 **FCR-27 RATES?**

14 A. The Company plans to implement the FCR-27 rates effective June 1, 2026.

15 **Q. HAS THE COMPANY SUBMITTED THE MFRS REQUIRED BY THE**
16 **COMMISSION IN THIS FILING?**

17 A. Yes. In accordance with Commission Rule 515-2-1-.04(6) and the Commission's
18 orders issued in Docket Nos. 20932 and 39638, the Company submitted historic
19 and projected MFRs with this filing. For purposes of FCR-27, the Company's
20 historic period covers January 2023 through December 2025, and the projected
21 MFRs incorporate a projected test period of June 2026 through May 2028 and are
22 based on the Company's 2026 Energy Budget.

1 **Q. WHAT VINTAGE OF FORECAST FOR PROJECTED FUEL COSTS ARE**
2 **REFLECTED IN THIS FILING?**

3 A. The fuel cost forecast included in the filing is based on the Company's 2026 Energy
4 Budget, which utilizes projected market data as of September 2025 to forecast the
5 optimal generation mix of resources and determine appropriate fuel expenses by
6 fuel type associated with each respective generation resource. The fuel price
7 assumptions included in the 2026 Energy Budget include associated marginal cost
8 data derived from established market sources and relevant indices. All the resources
9 assumed in the energy budget in the test period reflect those that have been
10 approved by the Commission through the Integrated Resource Plan ("IRP") or other
11 certification proceedings.

12 **Q. PLEASE EXPLAIN THE SALES FORECAST USED IN THIS FILING.**

13 A. The proposed FCR-27 rates were calculated based on the Company's 2026 Energy
14 Budget (*see* Exhibit ___ (ADH/MSB-3), Pages 1 and 2. Total demand for electricity
15 is forecasted to be 12% higher during the first twelve months of the FCR-27 test
16 period than it was for the first twelve months in FCR-26.

17 **IV. FCR-26 UNDER-RECOVERED FUEL BALANCE AND**
18 **HISTORIC FUEL COSTS**

19 **Q. PLEASE ELABORATE ON THE CHANGES THAT HAVE OCCURRED IN**
20 **THE FUEL MARKETS SINCE JUNE 2023 WHEN THE COMPANY SET**
21 **THE FCR-26 RATES.**

22 A. After experiencing a high level of price volatility with strong demand following the
23 impacts of the Russia-Ukraine war in 2022, coal prices remained relatively stable
24 over the 2023 through 2025 term. Coal prices began to decline in 2023 as coal
25 purchasing activity slowed with falling natural gas prices. Coal inventories rose to
26 elevated levels across the entire U.S. power sector through 2023, 2024, and into
27 2025. While coal prices fell with the decline in domestic demand, inflation-driven

1 increases in mining, labor, and equipment costs created a new, higher price floor.
2 Strong international demand also helped keep prices stable in 2023 and 2024. As
3 domestic coal inventories returned closer to historical levels in 2025, purchasing
4 activity accelerated and prompted a slight rise in prices. At the same time,
5 international demand softened, which helped limit overall price movement. The
6 combination of recovering domestic demand and easing international markets
7 resulted in a modest overall price increase in 2025.

8 Natural gas prices remained volatile from 2023 through 2025 even as they moved
9 below the extreme highs seen in 2022. In 2023 and 2024, strong production levels
10 and an absence of extended extreme weather periods created a looser supply–
11 demand balance, keeping Henry Hub prices low. By 2025, rising liquified natural
12 gas (“LNG”) export demand and steady domestic consumption tightened balances
13 and pushed prices higher. Over the three-year period, Henry Hub spot prices ranged
14 from \$1.23 to \$12.97, averaging \$2.53 in 2023, \$2.25 in 2024, and \$3.53 in 2025.

15 **Q. FOR THE FCR-27 HISTORIC PERIOD, HOW DID THE COMPANY’S**
16 **ACTUAL FUEL COSTS DIFFER FROM THE COMPANY’S BUDGETED**
17 **FUEL COSTS?**

18 A. The Company’s actual fuel costs for operations during the historic period were
19 \$185 million, or 2.2%, above budgeted costs. The primary factor impacting actual
20 costs was higher than expected coal generation, which was partially offset by lower
21 cost of natural gas generation and purchases driven primarily by the lower prices
22 of natural gas.

23 **Q. PLEASE FURTHER EXPLAIN THE INCREASE IN COAL GENERATION**
24 **DURING THE HISTORICAL PERIOD.**

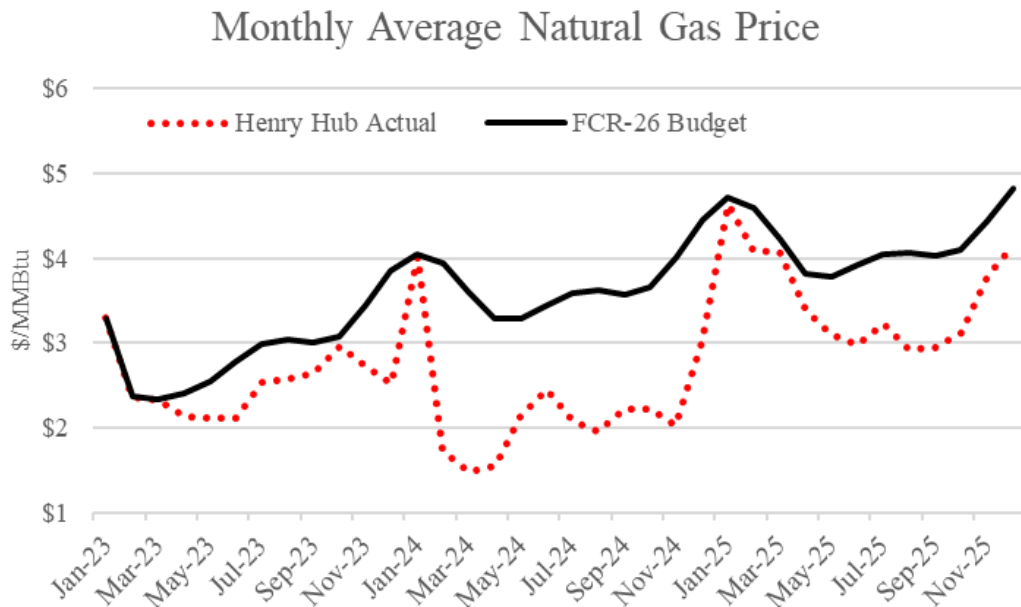
25 The coal generation during the historical period was approximately 22.3 million
26 MWh, or 141%, higher than budget. This higher-than-expected generation was
27 used to serve additional load during the historical period, primarily due to the lower

1 marginal cost of delivered coal, which averaged \$3.11/MMBtu, or 36% lower than
2 the marginal cost for delivered coal reflected in the FCR-26 budget. A key driver
3 in these lower costs is favorable contract negotiations for coal transportation
4 services in which the Company negotiated 20% to 30% rate reductions. As part of
5 the overall coal procurement strategy, the Company seeks to maintain a consistent
6 supply chain to mitigate coal supply constraints and ensure reliable, predictable,
7 and sustainable coal deliveries in volatile fuel markets. This approach will ensure
8 reliability of supply in times of high market demand while optimizing fuel costs
9 over time.

10 **Q. WHAT WAS THE CHANGE IN NATURAL GAS PRICES DURING THE**
11 **HISTORICAL PERIOD AND ITS IMPACT TO FUEL EXPENSES?**

12 Henry Hub monthly average gas prices during the historic period of January 2023
13 through December 2025 averaged \$2.77 per MMBtu, which was 23% lower than
14 budgeted average gas price of \$3.62 per MMBtu in FCR-26. Primarily as a result
15 of these lower natural gas prices, the Company's cost for gas generation, including
16 purchased power agreements ("PPAs") and hedge settlements, and affiliate and
17 non-affiliate energy purchases through the pool on a dollar per megawatt hour
18 ("\$/MWh") basis were \$3.19/MWh, or 9% below budget for the historic period,
19 which resulted in \$500 million in lower fuel expenses. **Chart 1** below shows the
20 comparison of the actual monthly natural gas prices at Henry Hub compared to the
21 prices used to set FCR-26 fuel rates.

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Chart 1

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3 Although the lower natural gas prices helped lower the cost of generation and
 4 purchases, it also resulted in lower prices charged to RTP customers than
 5 forecasted, which reduced the fuel revenues collected from those customers. As
 6 part of the update of fuel rates in the FCR-26 proceeding to reflect lower forward
 7 natural gas price curves, the Company made an adjustment in the budget to lower
 8 its cost of natural gas generation, including PPAs. For the projected RTP revenues,
 9 the assumptions underlying the RTP revenues continued to follow the 2023 Energy
 10 Budget, which reflected higher natural gas prices than those used to project fuel
 11 expenses in the approved FCR-26 budget. Considering the actual natural gas prices
 12 have further trended down since then, this resulted in lower RTP revenues of \$324
 13 million, or a decrease of 23% over the historical period compared to budget.

14 **Q. WHAT OTHER FACTORS IMPACTED THE UNDER-RECOVERY**
 15 **BALANCE DURING THE HISTORICAL PERIOD?**

16 For fuel prices related to other types of generation such as coal and nuclear
 17 generation, there were savings related to the resources during the historical period.

1 The cost of coal generation was \$2.55/MWh, or 5%, lower during the historical
2 period and the cost of nuclear generation was \$0.44/MWh, or 5% lower during the
3 same period. As noted in MFRH-2, the reduction in these fuel prices helped lower
4 the fuel expenses by \$40 million and \$30 million for coal and nuclear generation,
5 respectively.

6 Lastly, the Company incurred a higher carrying cost on the under-recovered
7 balance during the historical period primarily as result of the higher short-term debt
8 interest rates in the market. The short-term debt interest rates averaged 5.3% over
9 the historical period, which was 18% higher than the average interest rate forecasted
10 in the FCR-26 Budget. This contributed an additional \$34 million to the under-
11 recovery as noted in MFRH-2.

12 **Q. HOW DID THE COMPANY'S ACTUAL GENERATION PRODUCTION**
13 **AND ENERGY SALES IN THE FCR-27 HISTORIC PERIOD COMPARE**
14 **TO THE COMPANY'S FCR-26 BUDGET?**

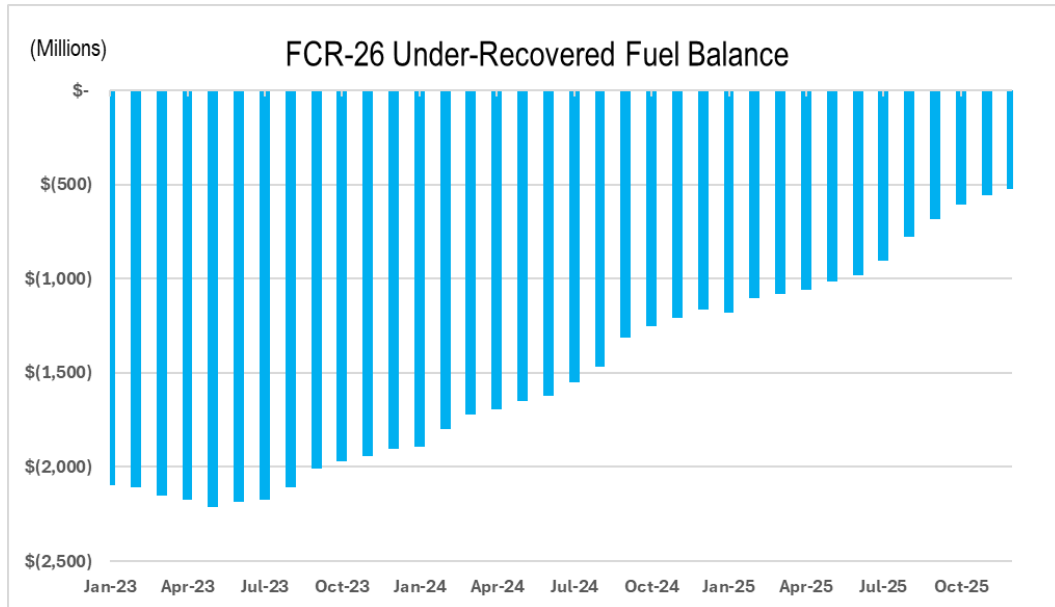
15 A. Retail loads were slightly above budget on a billed basis by approximately 1.4
16 million MWh (0.6%) during the historic period and the Company's total supply
17 requirement was above budget by approximately 12.4 million MWh (4.5%), driven
18 primarily by increase in wholesale sales of 171%.

19 **Q. WHAT IS THE STATUS OF THE FCR-26 UNDER-RECOVERED FUEL**
20 **BALANCE?**

21 A. As of December 31, 2025, the Company's total FCR-26 under-recovered fuel
22 balance was \$522 million, consisting of \$310 million under-recovered fuel balance
23 prior to FCR-26 and \$212 million of under-recovery accumulated since FCR-26
24 rates went into effect. The balance is projected to be \$300 million as of May 2026,
25 comprised almost entirely of under-recovery since FCR-26, with only \$449
26 thousand expected to remain from the under-recovery prior to FCR-26 by May

2026. The illustration of the reduction in fuel under-recovery balance during the historical period is presented in Chart 2 below.

Chart 2



Q. HAS THE COMPANY TRIGGERED THE IFR SINCE JUNE 1, 2023?

A. Yes, under the current IFR requirement, the Company filed a Retail FCR Status and IFR Notification and Plan in April 2025 and continuing monthly through August 2025, informing the Commission that the Company's FCR-26 Part A under-recovered fuel balance exceeded the IFR threshold of \$200 million. In each filing, the Company requested no change in rates for customers as the Company anticipated downward pressure in the fuel market to mitigate the under-recovery balance. Subsequently, the Company's Part A under-recovery balance decreased under the \$200 million threshold in September 2025 and continued below the threshold until December 2025, when the under-recovery balance again exceeded the \$200 million threshold. Given the expected near-term FCR-27 filing in February 2026, the Company requested no change in FCR-26 rates.

1 **Q. WERE THERE ANY ADJUSTMENTS IN THE HISTORICAL PERIOD**
2 **THAT HELPED REDUCE THE UNDER-RECOVERY BALANCE?**

3 A. As part of the ongoing litigation claim settlements related to the Company's spent
4 nuclear fuel costs with the United States government, the Company was awarded
5 payment for damages associated with Southern III and Southern IV claims,
6 respectively. As directed by the Commission, the fuel allocation of the awarded
7 amounts of \$55.2 million were directly credited to the fuel under-recovered balance
8 in 2024 to lower the fuel balance for customers.

9 In addition, the state of Georgia passed legislation to lower its state income tax rate
10 from 5.75% to 5.39% effective January 1, 2024, and further lowered its tax rate to
11 5.19% effective January 1, 2025. As a result, the Company recorded excess
12 accumulated deferred income taxes of \$11.0 million and \$2.2 million in 2024 and
13 2025, respectively, related to its fuel under-recovery balance, which was
14 concurrently applied to the fuel balance to reduce the under-recovery for customers.

15 **V. FCR-27 PROJECTED FUEL COSTS**

16 **Q. PLEASE DESCRIBE THE FUTURE OUTLOOK OF THE FUEL MARKET**
17 **FOR THE TEST PERIOD.**

18 A. Domestic coal prices have stabilized following the substantial volatility
19 experienced during 2021–2022 and the subsequent decline in demand and pricing
20 throughout 2023–2024. Although international market demand remains subdued,
21 increased domestic coal-fired generation has provided sufficient counterbalance to
22 mitigate the effects of weaker global conditions. With stockpiles returning to
23 historical norms, domestic purchasers continue to secure supply for 2026 and
24 subsequent years. This sustained domestic demand is expected to exert upward
25 pressure on prices; however, persistently weak international demand is likely to
26 temper these effects, resulting in overall price stability. As demand declined and
27 prices fell, Georgia Power secured long-term agreements with suppliers, aligned

1 with our coal procurement strategy, to ensure favorable pricing and reduce a portion
2 of price-risk exposure for our customers.

3 Looking ahead, natural gas fundamentals are expected to tighten over the coming
4 years. LNG export demand will continue to rise as additional liquefaction facilities
5 are brought online. At the same time, natural gas will serve as a critical fuel source
6 to support the substantial growth in electricity demand. Although production is
7 expected to increase to meet rising demand, supply growth faces risks, including
8 infrastructure constraints and continued capital discipline among producers. Taken
9 together, these factors suggest a tighter supply-demand balance and the potential
10 for continued natural gas price volatility.

11 **Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S PROJECTED**
12 **FUEL COSTS FOR THE FCR-27 TEST PERIOD.**

13 A. For FCR-27 test period, fuel costs are projected to be \$3.3 billion for the first 12
14 months and \$7.1 billion for the full 24-month test period as shown in
15 Exhibit___(ADH/MSB-1) Page 1. Overall, the total projected fuel cost for the
16 FCR-27 test period is approximately \$1.4 billion, or 25%, more than the projected
17 fuel cost for the FCR-26 test period as shown in MFRP-1, driven primarily by the
18 increase in forecast of natural gas prices and the increase in projected load
19 requirement. This is partially offset by the increase in revenues from the
20 corresponding higher load from retail and wholesale customers and decreases in the
21 price of coal and nuclear generation and energy purchases from the pool. The
22 comparison of projected fuel costs by resources between the FCR-27 test period
23 and the FCR-26 test period is presented in **Table 3** below.

Table 3

**Comparison of Projected Fuel Costs
FCR-27 vs FCR-26**

	FCR-27 Test Period (June 2026 - May 2028)			FCR-26 Test Period (June 2023 - May 2025)			FCR-27 vs FCR-26		
	(\$ Millions)	(GWh)	(\$/MWh)	(\$ Millions)	(GWh)	(\$/MWh)	% Change		
Natural Gas*	\$ 2,848	76,187	\$ 37.38	\$ 2,132	65,992	\$ 32.31	34%	15%	16%
Coal	1,258	35,487	35.44	499	9,746	51.15	152%	264%	-31%
Nuclear	427	48,871	8.74	448	46,376	9.66	-5%	5%	-9%
Solar & Hydro	-	4,187	-	-	4,004	-	-	5%	-
Renewable PPAs**	1,218	24,915	48.89	949	18,633	50.93	28%	34%	-4%
Purchases	1,322	36,395	36.34	1,633	39,838	40.98	-19%	-9%	-11%
Total	\$ 7,073	226,041	\$ 31.29	\$ 5,660	184,589	\$ 30.66	25%	22%	2%

*Includes PPA's for which GPC is responsible for purchasing fuel; includes hedge gains/losses

**Includes Solar, Biomass, Wind, and Battery PPA resources

2

3 **Q. HOW DOES THE PROJECTED PRICE OF NATURAL GAS INCLUDED**
4 **IN THE FCR-27 BUDGET COMPARE TO THE PRICE INCLUDED IN**
5 **THE FCR-26 BUDGET?**

6 A. During the 24-month FCR-27 test period, using market data as of September 2025,
7 the Company projects natural gas prices will average \$3.89 per MMBtu, which is
8 6% higher than the average natural gas price reflected in the 24-month test period
9 from the approved FCR-26 budget of \$3.66 per MMBtu. As a result, compared to
10 the FCR-26 test period, fuel cost for natural gas, including PPAs, is projected to
11 increase by 21% from \$30.91/MWh to \$37.38/MWh. This increase yields \$427
12 million of additional natural gas fuel expense, which is partially offset by the
13 difference in hedge costs of \$92 million.

14 **Q. HOW DOES THE COMPANY'S PROJECTED ENERGY SALES IN THE**
15 **TEST PERIOD COMPARE TO THE FCR-26 BUDGET TEST PERIOD?**

16 A. The Company anticipates significant increase in total energy sales driven primarily
17 by higher retail load of 35.7 million MWh, or an increase of 21%. Wholesale sales
18 are also projected to increase by 3.7 million MWh, or an increase of 94%, driven
19 by new wholesale contracts signed since FCR-26. On a total basis, the projected

1 load is 39.4 million MWh higher, or 22%. To serve this additional load, the
2 Company projects increases across all of its mix of generation portfolio. More
3 specifically, the Company projects higher generation of coal, natural gas, and
4 nuclear fuel of 264%, 15%, and 5%, respectively. Similar to the historical period,
5 the significant increase in coal generation during the test period is primarily
6 attributed to the lower marginal cost of coal in FCR-27, which is 33% below the
7 marginal coal cost assumptions included in FCR-26. Likewise, the FCR-26 budget
8 did not include any operational must-run requirements for the Company's
9 generation fleet, but FCR-27 budget includes must-run requirements for Plant
10 Bowen to address system constraints and ensure operational reliability. In addition,
11 the Company's solar generation and its solar PPAs combined are also expected to
12 produce 46% higher generation during the FCR-27 test period. The higher
13 generation of resources during the FCR-27 test period is projected to result in an
14 additional \$1.4 billion in fuel expenses. This increase will be mostly offset by the
15 revenues from additional energy sales projected in the test period from both retail
16 and wholesale customers.

17 **Q. WILL THE INCREASE IN LARGE LOAD CUSTOMERS IMPACT FUEL**
18 **COST RESPONSIBILITY FOR EXISTING CUSTOMERS?**

19 A. No. The increase in fuel expenses due to higher forecasted generation from
20 resources reflects the growth in demand, which includes economic development
21 growth from large loads. These large load customers have already provided benefits
22 to customers by allowing the Company to keep base rates stable over the next three
23 years. Moreover, the Company has been able to commit to a large load revenue
24 forecast that will provide downward pressure on rates in the Company's next base
25 rate case. Therefore, the increase in generation is in part due to securing the loads
26 that will provide this value. Georgia Power is not proposing to change the structure
27 or framework for how fuel costs are recovered from current or future customers.
28

1 Additionally, much of the KWh sales from these large load customers is priced at
2 RTP. For RTP load, a large load customer's fuel contribution reflects the marginal
3 costs incurred by the Company in each hour. Further, large load customers bear the
4 risk of higher fuel prices and are assessed those costs directly during higher cost
5 hours. Thus, large load customers will bear the appropriate cost responsibility in
6 each hour for the fuel cost they impose on the Company and the overall revenues
7 collected from these customers are projected to provide significant benefits that will
8 reduce rate pressures for all Georgia Power customers.

9 **Q. ARE THERE OTHER FACTORS PROVIDING DOWNWARD PRESSURE**
10 **ON PROJECTED FUEL COSTS IN THE FCR-27 TEST PERIOD?**

11 A. Compared to the FCR-26 test period, the fuel price for coal and nuclear generation,
12 as well as purchases, are projected to decrease during the FCR-27 test period. The
13 \$/MWh fuel cost for coal and nuclear generation are projected to go down by 31%
14 and 9%, respectively. The reduction in the delivered coal price forecast is based on
15 newly negotiated transportation service agreements entered into by the Company
16 since FCR-26, which provide significantly lower transportation prices for
17 customers. The reduced fuel prices for coal and nuclear generation projects lower
18 fuel expenses of \$153 million and \$42 million, respectively, during the FCR-27 test
19 period. Likewise, the fuel price of affiliate and non-affiliate energy purchases from
20 the pool are expected to be lower by 11% in FCR-27 test period, which results in
21 \$180 million of lower projected fuel costs. The update of lower natural gas prices
22 in approved FCR-26 budget did not adjust the fuel expenses associated with energy
23 purchases from the pool and therefore, the energy purchases reflected much higher
24 underlying natural gas prices and resulted in higher fuel expenses in FCR-26 test
25 period.

1 **Q. ARE THERE ANY ADJUSTMENTS TO NET FUEL COSTS IN THE**
2 **PROJECTED FCR-27 TEST PERIOD?**

3 A. Yes, the Company procured firm transportation from Transco for future generation
4 of new combined cycle units at Plants Bowen and Wansley, which were approved
5 by the Commission through the All-Source Certification in 2025. The capacity
6 payments for this pipeline are projected to begin in November 2027, prior to the in-
7 service dates of those units. The Transco Southeast Supply Enhancement was the
8 only project that could provide firm transportation service to Plants Bowen and
9 Wansley to meet the units' planned commercial operation dates. The Company was
10 one of several shippers in this project and the project in-service date was driven by
11 the requirements of a much larger shipper. Therefore, timely procurement of
12 capacity to support Plants Bowen and Wansley required the Company to participate
13 in a project that will be available prior to commercial operation of the plants. For
14 this firm transportation capacity projected in the FCR-27 test period, the Company
15 plans to monetize the capacity in the market to generate revenues and have reflected
16 the potential proceeds from the sale to FCR to offset the firm transportation
17 expenses in this filing.

18 **VI. NATURAL GAS HEDGING**

19 **Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS CURRENT**
20 **NATURAL GAS HEDGING PROGRAM?**

21 A. Yes. While the current hedging program has worked as intended and continues to
22 provide benefits for customers, the Company proposes to expand the hedging
23 program given the expectation for increasing exposure to natural gas based on the
24 increase in natural gas burn projections in the Company's budget.

25 **Q. WHY DOES THE COMPANY ENGAGE IN NATURAL GAS HEDGING?**

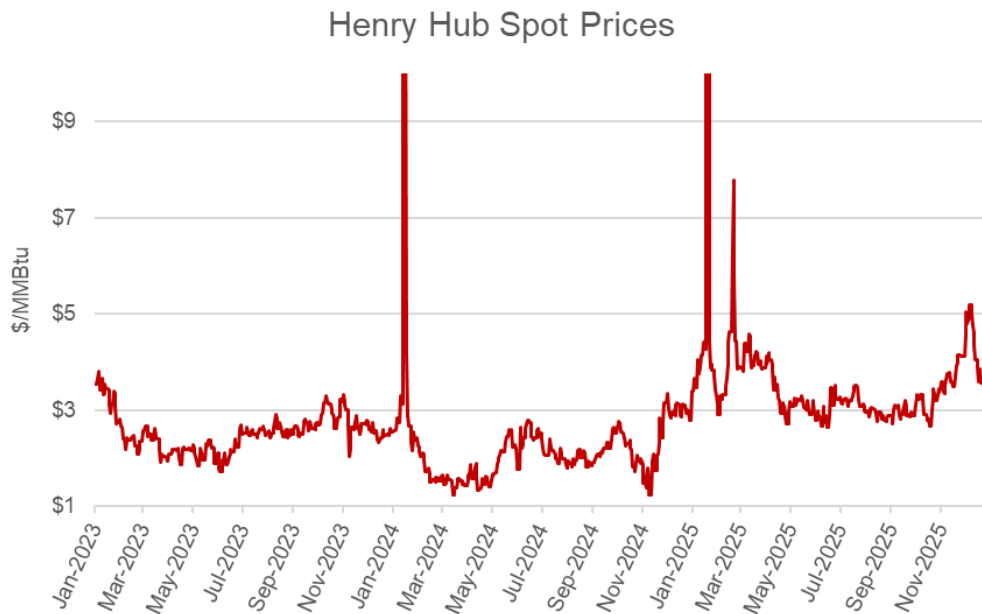
26 A. The Company engages in natural gas hedging to help mitigate the risk of upward
27 price volatility in the natural gas market. Natural gas fired generation is projected

1 to be the largest energy source for Georgia Power during the FCR-27 test period,
2 with approximately 40% of the total projected fuel costs coming from natural gas.
3 Because the cost of natural gas is a significant portion of the Company's fuel costs
4 and remains subject to significant volatility, it is appropriate for the Company to
5 mitigate its natural gas costs by fixing and/or capping a portion of the prices it pays
6 for gas. This benefits customers by providing greater stability in the Company's
7 fuel costs and reducing the impact of increasing gas prices.

8 **Q. ARE NATURAL GAS PRICES STILL SUBJECT TO VOLATILITY?**

9 A. Yes. Natural gas prices remain subject to significant volatility. As shown in
10 **Chart 3** below, this volatility can be seen in the wide range of spot prices at Henry
11 Hub, which ranged from \$1.23 to \$12.97 per MMBtu in 2023 through 2025. Even
12 small movements in gas prices can impact the Company's fuel balance and,
13 ultimately, costs to customers. For a Company like Georgia Power that anticipates
14 consuming more than 250 million MMBtu of natural gas per year, a robust hedging
15 program serves as a critical tool to mitigate upward price volatility for customers.

16 *Chart 3*



1 In fact, as recently as late January 2026, Henry Hub natural gas prices rose above
2 \$30 per MMBtu during Winter Storm Fern, illustrating the ongoing potential for
3 volatility in natural gas markets.

4 **Q. WHAT ARE THE CHANGES REQUESTED BY THE COMPANY TO THE**
5 **CURRENT HEDGING PROGRAM?**

6 A. Based on the Commission approval in Docket No. 44902, the Company is currently
7 allowed to hedge 40% of its budgeted natural gas burn up to 36 months. The
8 Company is requesting the limits of the hedging program be increased to 60% of
9 its budgeted natural gas burn up to 48 months. These adjustments will provide
10 greater protection for customers against increasing exposure to price volatility in
11 the natural gas market as seen historically in Chart 3 above.

12 **Q. IS THE PROJECTED NATURAL GAS BURN EXPECTED TO INCREASE**
13 **IN THE FORECASTED PERIODS?**

14 A. Yes. On an annual basis, the MMBtu of natural gas burn projected in the test period
15 in FCR-27 is 522 million MMBtu compared to the 461 million MMBtu that were
16 projected in the test period in FCR-26 Budget. This higher burn volume leads to
17 increased exposure to price volatility in the natural gas market. By locking in
18 additional percentage of natural gas over a longer horizon, the hedges can serve to
19 reduce this significant price risk for the benefit of customers.

20 **VII. INTERIM FUEL RIDER**

21 **Q. SHOULD THE IFR MECHANISM BE CONTINUED?**

22 A. Yes. The IFR mechanism should be continued because it helps mitigate the
23 accumulation of a substantial over-recovered or under-recovered fuel balance,
24 thereby benefiting customers and the Company. The Commission initially

1 approved the IFR mechanism in FCR-21, and it has served as a useful tool for
2 customers and the Company since then.

3 **Q. ARE ANY CHANGES TO THE IFR MECHANISM NECESSARY AT THIS**
4 **TIME?**

5 A. Yes. The Company proposes to increase the IFR threshold from the current amount
6 of \$200 million approved by the Commission to \$300 million.

7 **Q. HOW WOULD THIS CHANGE TO THE IFR MECHANISM BE APPLIED?**

8 A. Consistent with the currently approved IFR mechanism, the \$300 million will be
9 applied in either direction of over-recovery or under-recovery balance with the
10 current maximum percentage of 40% of cumulative rate change unaltered from the
11 current approved level. The Company proposes that the timing and the filing
12 requirements remain the same. The increase in threshold will provide greater rate
13 stability for customers and will allow increased flexibility to absorb natural fuel
14 price fluctuations and normal swings of over or under-recovery balances on a
15 monthly basis.

16 **VIII. RENEWABLE RESOURCE PROCUREMENT COST RECOVERY**

17 **Q. HOW DOES GEORGIA POWER RECOVER ITS COSTS FOR**
18 **DEVELOPING AND EVALUATING RENEWABLE REQUESTS FOR**
19 **PROPOSALS?**

20 A. Georgia Power structures its Renewable Requests for Proposals (“RFPs”) to collect
21 Bid Fees and Winner’s Fees to defray the cost of the RFP process, to hire the
22 Independent Evaluator, and to evaluate the submissions received in the RFP. Where
23 the Bid Fees and Winners’ Fees do not cover the full cost of Georgia Power’s RFP
24 administration and evaluation costs, those costs are currently recovered through the
25 fuel clause.

1 **Q. WHERE DID THE COMMISSION AUTHORIZE THE COMPANY TO**
2 **RECOVER THESE COSTS THROUGH THE FUEL CLAUSE?**

3 A. In resolution of Georgia Power's 2016, 2019, and 2022 IRPs, the Commission
4 approved Stipulations that specifically provided for the cost recovery of all Utility
5 Scale and Distributed Generation RFP-related costs to go through fuel to the extent
6 they were not recovered elsewhere.¹ Since the benefits of renewable energy
7 procured through PPAs accrue to customers in the form of lower fuel costs (and
8 thus lower FCR rates) over time, it is appropriate to recover the costs associated
9 with procuring these energy-benefiting resources through the FCR.

10 **Q. WHAT OTHER RENEWABLE COSTS OR REVENUES FLOW**
11 **THROUGH FUEL?**

12 A. As presently approved, all RFP-related costs and revenues not otherwise recovered
13 by Bid Fees or Winners Fees are recovered through the fuel clause. Such costs may
14 include the Company's labor costs from dedicated procurement personnel and the
15 time spent by internal partners supporting the development of a given RFP (e.g.
16 Transmission, Resource Planning, Environmental Affairs, etc.) as well as the cost
17 of the Independent Evaluator, costs for the economic and transmission evaluations,
18 and termination fees. For example, bid security retained by Georgia Power if a
19 Short List bidder elects not to execute a PPA after being named to the Short List is
20 credited to the fuel clause to the benefit of all customers. The same is true of any
21 termination payment received for a PPA that is terminated early. In addition, once
22 PPAs are in effect, all payments to counterparties are processed through the FCR.

23 The Commission also approved the Company to recover through fuel any
24 incremental renewable and nonrenewable resources ("RNR") costs not otherwise

¹ *Order Adopting Stipulation*, Georgia Public Service Commission, Docket No. 44160 (July 29, 2022) at 23-25; *Order Adopting Stipulation as Amended*, Georgia Public Service Commission, Docket No. 42310 (July 29, 2019) attached Stipulation paras. 3 and 5; *Order Adopting Stipulations*, Georgia Public Service Commission, Docket No. 40161 (August 2, 2016) attached Stipulation para. 3.

1 recovered through the RNR program² as well as the charges collected from
2 customers participating in the Company's Clean and Renewable Energy
3 Subscription ("CARES") Program.³ Specifically, the Commission provided as
4 follows:

5 The following will be included in the fuel clause and recovered
6 through the Fuel Cost Recovery Mechanism ("FCR") all revenues
7 collected through the CARES Program, with the exception of the
8 additional sum as described in Paragraph 23, and (ii) all appropriate
9 costs that are not recovered elsewhere by the Company and are
10 incurred in connection with the procurement of the aforementioned
11 resources for subscription in the CARES Program. CARES Program
12 costs and revenues which are to be included in FCR include but are
13 not limited to the following: (i) the costs to implement and
14 administer the CARES Program, (ii) the bid fees collected in
15 connection with the CARES Program, the fees collected from
16 subscribing customers, and (iii) the PPA that are executed to supply
17 the CARES Program, including any payments for PPAs made by
18 participants.

19 **Q. WHAT IS GEORGIA POWER'S REQUEST REGARDING RECOVERY**
20 **OF RENEWABLE RFP RELATED COSTS GOING FORWARD?**

21 A. Georgia Power requests that the Commission continue to authorize Georgia Power
22 to recover all Renewable RFP (utility scale and distributed generation) and
23 renewable subscription program-related costs not otherwise recovered by the
24 Company through Bid Fees and Winner's Fees through the fuel clause, consistent
25 with past practice.

² Order Approving Georgia Power Company's Request to Apply the Renewable Cost Benefit Framework to Behind the Meter Solar Technologies and to Adjust the Renewable Energy Development Initiative Distributed Generation Program Schedule, Georgia Public Service Commission, Docket Nos. 40161 and 16573 (June 7, 2017); see also Georgia Power's Application to Apply the Renewable Cost Benefit Framework to Behind the Meter Solar Technologies and to Adjust the Renewable Energy Development Initiative Distributed Generation Program Schedule (including the BTM Joint Recommendation as Attachment 1), Georgia Public Service Commission, Docket Nos. 40161 and 16573 (June 1, 2017).

³ Order Approving CARES Program, Tariffs, and Agreements with Modification, Georgia Public Service Commission, Docket No. 44847 (January 24, 2023).

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IX. CONCLUSION

Q. IS THE COMPANY PROPOSING A SPECIFIC DATE BY WHICH TO FILE ITS NEXT FUEL CASE?

A. No. The Company is not proposing a specific date for its next fuel case. Instead, the Company proposes to continue its semi-annual reporting of projected monthly fuel revenues, fuel expenses, monthly over or under collections, and projected fuel balances through the FCR-27 test period to help ensure actual fuel costs are recovered as expected.

With the Company's request in this case, the Company anticipates recovering the FCR-26 under-recovered fuel balance over 36 months, which extends beyond the FCR-27 projected test period by 12 months. By maintaining the flexibility to set the date for the next fuel case—rather than setting a firm date now that aligns with the end of the FCR-27 projected test period—the Company and the Commission will monitor the fuel balance and potentially eliminate the FCR-26 under-recovered fuel balance before the next fuel case is filed. The Company's recommended change to the IFR mechanism will also enable the Company and the Commission to respond in a more timely and effective manner to fuel price volatility, thereby further mitigating the need to establish a fixed date for the next fuel case at this time.

For these reasons, a less prescriptive and more flexible, collaborative approach to determining the date of the next fuel filing is appropriate. Additionally, by not setting a specific date for the next filing, the Company and the Commission will avoid the need for formal deferral orders if future circumstances demonstrate that the fuel rates approved in this proceeding are sufficient beyond the FCR-27 test period.

1 **Q. PLEASE SUMMARIZE THE COMPANY’S REQUEST IN THIS FILING.**

2 A. For the reasons set forth herein, the Company respectfully seeks approval of its
3 Fuel Cost Recovery Application, which includes the following requests:

- 4 • To set fuel rates to recover fuel costs as projected in the Company’s FCR-
5 27 test period (June 2026 through May 2028);
- 6 • To increase the amount by which the Company can adjust rates through the
7 IFR mechanism, giving the Company and the Commission more flexibility
8 to timely address fuel price volatility;
- 9 • To expand the natural gas hedging program to better mitigate volatility of
10 natural gas prices in the market; and
- 11 • To authorize Georgia Power to recover all Renewable RFP (utility scale and
12 distributed generation) and renewable subscription program-related costs
13 not otherwise recovered by the Company through Bid Fees and Winner’s
14 Fees, be recovered through the fuel clause.

15 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

16 A. Yes.

GEORGIA POWER COMPANYProtected Fuel Expense
(Dollars in Thousands)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No.	DESCRIPTION	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	STEAM POWER (Account 501)												
1	Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	Yates Units 6-7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	Total Steam Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	NUCLEAR POWER (Account 518)												
5	Hatch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	Vogtle	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
7	Total Nuclear Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	SELF-BUILD BATTERY (Account 577)	\$ (219)	\$ (270)	\$ (1,152)	\$ (794)	\$ (307)	\$ (315)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	OTHER POWER (Account 547)												
9	Mohitosh CCs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	McDonough CCs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
11	Yates 8-10 CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
12	Other CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
13	Total Other Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
14	POOL AND ECONOMY PURCHASES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	CONTRACT PURCHASED POWER (Account 555)												
15	Southern Electric Generating Company	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
16	Vogtle Buyback from MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
17	Walton EMC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
18	Misc. Purchased Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
19	Mid-Ga	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
20	Southern Power - Wansley 7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
21	Southern Power - Harris	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
22	Southern Power - Dahlberg CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
23	Southern Power - Addison CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
24	Monroe	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
25	Santa Rosa PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
26	Heard County CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
27	Solar PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
28	Biomass PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
29	Wind PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
30	Battery PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
31	Total - Contract Purchased Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
32	EMISSION ALLOWANCES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
33	NATURAL GAS HEDGE (GAIN)/LOSS	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
34	TOTAL FUEL EXPENSES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
35	SALES FOR RESALE (Account 447)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
36	POOL AND ECONOMY SALES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
37	ECONOMY SALES PROFITS	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
38	SENIOR CITIZEN DISCOUNT	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
39	NET RENEWABLES PROGRAM EXPENSES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
40	FIRM TRANSPORTATION FOR FUTURE GENERATION	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
41	SALE PROCEEDS FROM FIRM TRANSPORTATION	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
42	NET RECOVERABLE FUEL COSTS	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
43	CARRYING COST ON CUMULATIVE (OVER)/UNDER RECOVERY - Part A	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
44	CARRYING COST ON CUMULATIVE (OVER)/UNDER RECOVERY - Part B	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
45	NET RECOVERABLE FUEL COSTS (incl Carrying Costs)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
46	RTP FUEL REVENUES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
47	NET RECOVERABLE FUEL COSTS	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANYProjected Fuel Expense
(Dollars in Thousands)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No.	DESCRIPTION	Jun-27 (15)	Jul-27 (16)	Aug-27 (17)	Sep-27 (18)	Oct-27 (19)	Nov-27 (20)	Dec-27 (21)	Jan-28 (22)	Feb-28 (23)	Mar-28 (24)	Apr-28 (25)	May-28 (26)	TOTAL (27)
	STEAM POWER (Account 501)													
1	Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	Yates Units 6-7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	Total Steam Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	NUCLEAR POWER (Account 518)													
5	Halch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	Vogtle	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
7	Total Nuclear Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	SELF-BUILD BATTERY (Account 577)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	OTHER POWER (Account 547)													
9	McIntosh CCs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	McDonough CCs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
11	Yates 8-10 CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
12	Other CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
13	Total Other Power	REDACTED	REDACTED	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
14	POOL AND ECONOMY PURCHASES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	\$ 81,773	\$ 76,560	\$ 84,617	\$ 50,293	\$ 59,562	\$ 352,805
	CONTRACT PURCHASED POWER (Account 555)													
15	Southern Electric Generating Company	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
16	Vogtle Buyback from MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
17	Walton EMC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
18	Misc. Purchased Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
19	Mid-Ga	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
20	Southern Power - Wansley 7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
21	Southern Power - Harris	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
22	Southern Power - Dahlberg CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
23	Southern Power - Addison CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
24	Monroe	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
25	Santa Rosa PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
26	Heard County CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
27	Solar PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
28	Biomass PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
29	Wind PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
30	Battery PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
31	Total - Contract Purchased Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
32	EMISSION ALLOWANCES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
33	NATURAL GAS HEDGE (GAIN)/LOSS	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
34	TOTAL FUEL EXPENSES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	\$ 7,073,351
35	SALES FOR RESALE (Account 447)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
36	POOL AND ECONOMY SALES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
37	ECONOMY SALES PROFITS	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
38	SENIOR CITIZEN DISCOUNT	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
39	NET RENEWABLES PROGRAM EXPENSES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
40	FIRM TRANSPORTATION FOR FUTURE GENERATION	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
41	SALE PROCEEDS FROM FIRM TRANSPORTATION	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
42	NET RECOVERABLE FUEL COSTS	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
43	CARRYING COST ON CUMULATIVE (OVER)/UNDER RECOVERY - Part A	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
44	CARRYING COST ON CUMULATIVE (OVER)/UNDER RECOVERY - Part B	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
45	NET RECOVERABLE FUEL COSTS (incl Carrying Costs)	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
46	RTP FUEL REVENUES	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
47	NET RECOVERABLE FUEL COSTS	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	\$ 5,283,238

Note: Details may not add to totals due to rounding.

PUBLIC DISCLOSURE

Errata Exhibit ____ (ADH/MSB-2) P
Docket No. !GEORGIA POWER COMPANYEstimated Generation
(gWh)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No.	DESCRIPTION	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	<u>STEAM POWER</u>												
1	Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	Yates Units 6-7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	Total Steam Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	<u>NUCLEAR POWER</u>												
5	Hatch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	Vogtle	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
7	Total Nuclear Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	<u>HYDRO POWER</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	<u>SELF-BUILD SOLAR</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	<u>SELF-BUILD BATTERY</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	<u>OTHER POWER</u>												
11	McIntosh CCs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
12	McDonough CCs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
13	Yates 8-10 CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
14	Other CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
15	Total Other Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
16	<u>NET POOL AND ECONOMY PURCHASES AND SALES</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	<u>CONTRACT PURCHASED POWER</u>												
17	Southern Electric Generating Company	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
18	Vogtle Buyback from MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
19	Walton EMC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
20	Misc. Purchased Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
21	Mid-Ga	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
22	Southern Power - Wansley 7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
23	Southern Power - Harris	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
24	Southern Power - Dahlberg CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
25	Southern Power - Addison CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
26	Monroe	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
27	Santa Rosa PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
28	Heard County CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
29	Solar PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
30	Biomass PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
31	Wind PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
32	Battery PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
33	Total - Contract Purchased Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
34	<u>SALES FOR RESALE</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
35	TOTAL NET GENERATION	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Note: Details may not add to totals due to rounding.

PUBLIC DISCLOSURE

Errata Exhibit ____ (ADH/MSB-2) P
Docket No. !GEORGIA POWER COMPANYEstimated Generation
(gWh)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No.	DESCRIPTION	Jun-27 (15)	Jul-27 (16)	Aug-27 (17)	Sep-27 (18)	Oct-27 (19)	Nov-27 (20)	Dec-27 (21)	Jan-28 (22)	Feb-28 (23)	Mar-28 (24)	Apr-28 (25)	May-28 (26)
(1)	(2)												
	<u>STEAM POWER</u>												
1	Bowen	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	Scherer	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	Yates Units 6-7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	Total Steam Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	<u>NUCLEAR POWER</u>												
5	Hatch	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	Vogtle	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
7	Total Nuclear Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	<u>HYDRO POWER</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	<u>SELF-BUILD SOLAR</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	<u>SELF-BUILD BATTERY</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	<u>OTHER POWER</u>												
11	McIntosh CCs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
12	McDonough CCs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
13	Yates 8-10 CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
14	Other CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
15	Total Other Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
16	<u>NET POOL AND ECONOMY PURCHASES AND SALES</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
	<u>CONTRACT PURCHASED POWER</u>												
17	Southern Electric Generating Company	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
18	Vogtle Buyback from MEAG	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
19	Walton EMC	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
20	Misc. Purchased Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
21	Mid-Ga	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
22	Southern Power - Wansley 7	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
23	Southern Power - Harris	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
24	Southern Power - Dahlberg CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
25	Southern Power - Addison CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
26	Monroe	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
27	Santa Rosa PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
28	Heard County CTs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
29	Solar PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
30	Biomass PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
31	Wind PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
32	Battery PPAs	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
33	Total - Contract Purchased Power	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
34	<u>SALES FOR RESALE</u>	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
35	TOTAL NET GENERATION	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Note: Details may not add to totals due to rounding.

PUBLIC DISCLOSURE

Errata Exhibit ____ (ADH/MSB-2) P
Docket No. !GEORGIA POWER COMPANYEstimated Generation
(gWh)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No.	DESCRIPTION	TOTAL
(1)	(2)	(27)
	<u>STEAM POWER</u>	
1	Bowen	REDACTED
2	Scherer	REDACTED
3	Yates Units 6-7	REDACTED
4	Total Steam Power	REDACTED
	<u>NUCLEAR POWER</u>	
5	Hatch	REDACTED
6	Vogtle	REDACTED
7	Total Nuclear Power	REDACTED
8	<u>HYDRO POWER</u>	REDACTED
9	<u>SELF-BUILD SOLAR</u>	REDACTED
10	<u>SELF-BUILD BATTERY</u>	REDACTED
	<u>OTHER POWER</u>	
11	McIntosh CCs	REDACTED
12	McDonough CCs	REDACTED
13	Yates 8-10 CTs	REDACTED
14	Other CTs	REDACTED
15	Total Other Power	REDACTED
16	<u>NET POOL AND ECONOMY PURCHASES AND SALES</u>	REDACTED
	<u>CONTRACT PURCHASED POWER</u>	
17	Southern Electric Generating Company	REDACTED
18	Vogtle Buyback from MEAG	REDACTED
19	Walton EMC	REDACTED
20	Misc. Purchased Power	REDACTED
21	Mid-Ga	REDACTED
22	Southern Power - Wansley 7	REDACTED
23	Southern Power - Harris	REDACTED
24	Southern Power - Dahlberg CTs	REDACTED
25	Southern Power - Addison CTs	REDACTED
26	Monroe	REDACTED
27	Santa Rosa PPAs	REDACTED
28	Heard County CTs	REDACTED
29	Solar PPAs	REDACTED
30	Biomass PPAs	REDACTED
31	Wind PPAs	REDACTED
32	Battery PPAs	REDACTED
33	Total - Contract Purchased Power	REDACTED
34	<u>SALES FOR RESALE</u>	REDACTED
35	TOTAL NET GENERATION	218,415

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANYEstimated Total Billed Sales
(MWh)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No. (1)	DESCRIPTION (2)	<u>Jun-26</u> (3)	<u>Jul-26</u> (4)	<u>Aug-26</u> (5)	<u>Sep-26</u> (6)	<u>Oct-26</u> (7)	<u>Nov-26</u> (8)	<u>Dec-26</u> (9)	<u>Jan-27</u> (10)	<u>Feb-27</u> (11)	<u>Mar-27</u> (12)	<u>Apr-27</u> (13)	<u>May-27</u> (14)
1	Residential	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	Commercial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	Industrial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	MARTA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
5	Street & Highway	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	Total FCR Applicable Sales	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Line No. (1)	DESCRIPTION (2)	<u>Jun-27</u> (15)	<u>Jul-27</u> (16)	<u>Aug-27</u> (17)	<u>Sep-27</u> (18)	<u>Oct-27</u> (19)	<u>Nov-27</u> (20)	<u>Dec-27</u> (21)	<u>Jan-28</u> (22)	<u>Feb-28</u> (23)	<u>Mar-28</u> (24)	<u>Apr-28</u> (25)	<u>May-28</u> (26)	TOTAL (27)
7	Residential	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	Commercial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	Industrial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	MARTA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
11	Street & Highway	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
12	Total FCR Applicable Sales	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	209,075,539

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANYEstimated FCR Applicable Sales
(MWh)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No.	DESCRIPTION	<u>Jun-26</u> (3)	<u>Jul-26</u> (4)	<u>Aug-26</u> (5)	<u>Sep-26</u> (6)	<u>Oct-26</u> (7)	<u>Nov-26</u> (8)	<u>Dec-26</u> (9)	<u>Jan-27</u> (10)	<u>Feb-27</u> (11)	<u>Mar-27</u> (12)	<u>Apr-27</u> (13)	<u>May-27</u> (14)
1	Residential	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	Commercial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	Industrial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	MARTA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
5	Street & Highway	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	Total FCR Applicable Sales	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Line No.	DESCRIPTION	<u>Jun-27</u> (15)	<u>Jul-27</u> (16)	<u>Aug-27</u> (17)	<u>Sep-27</u> (18)	<u>Oct-27</u> (19)	<u>Nov-27</u> (20)	<u>Dec-27</u> (21)	<u>Jan-28</u> (22)	<u>Feb-28</u> (23)	<u>Mar-28</u> (24)	<u>Apr-28</u> (25)	<u>May-28</u> (26)	TOTAL (27)
7	Residential	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	Commercial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	Industrial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	MARTA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
11	Street & Highway	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
12	Total FCR Applicable Sales	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	143,524,387

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

**Calculation of Fuel Cost Recovery Rate
Seasonal Rate - Summer
(Dollars in Thousands)**

**SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028**

Line No.	Description	Amounts
(1)	(2)	(3)
1	Test Period Recoverable Fuel Costs for Part "A"	\$ 1,953,540
2	Test Period Estimated FCR Applicable Sales	<u>53,628,372 MWh</u>
3	Part "A" (Line 1 ÷ Line 2)	3.6427 ¢/kWh
4	FCR-27 Under-Recovery Part "B" including Carrying Costs	115,253
5	Estimated FCR Applicable Sales (3-Year Amortization)	<u>81,200,227 MWh</u>
6	Part "B" (Line 4 ÷ Line 5)	<u>0.1419 ¢/kWh</u>
7	Total Recoverable Fuel Costs (Line 1 + Line 4)	\$ 2,068,793
8	Total Average Fuel Rate (Line 3 + Line 6)	<u><u>3.7846 ¢/kWh</u></u>

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

**Calculation of Fuel Cost Recovery Rate
Seasonal Rate - Winter
(Dollars in Thousands)**

**SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028**

Line No.	Description	Amounts
(1)	(2)	(3)
1	Test Period Recoverable Fuel Costs for Part "A"	\$ 3,319,282
2	Test Period Estimated FCR Applicable Sales	<u>89,896,014 MWh</u>
3	Part "A" (Line 1 ÷ Line 2)	3.6924 ¢/kWh
4	FCR-27 Under-Recovery Part "B" including Carrying Costs	192,661
5	Estimated FCR Applicable Sales (3-Year Amortization)	<u>136,502,254 MWh</u>
6	Part "B" (Line 4 ÷ Line 5)	<u>0.1411 ¢/kWh</u>
7	Total Recoverable Fuel Costs (Line 1 + Line 4)	\$ 3,511,943
8	Total Average Fuel Rate (Line 3 + Line 6)	<u><u>3.8335 ¢/kWh</u></u>

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

**Adjustment for Prior Period Under-Recovery
(Dollars in Thousands)**

**SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028**

Line No.	Description	Total	Summer	Winter
<u>(1)</u>	<u>(2)</u>	<u>(3)</u>	<u>(4)</u>	<u>(5)</u>
1	Projected Under-Recovered Balance As of May 31, 2026	\$ 296,095		
2	Estimated mWh Applicable Sales	217,702,481	81,200,227	136,502,254
3	Percentage of Total Applicable Sales	100%	37.30%	62.70%
4	Projected Under Recovered FCR Balance	\$ 296,095	\$ 110,440	\$ 185,656
5	Recovery Per 12 month Period	\$ 98,698	\$ 36,813	\$ 61,885

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

**APPLICATION OF LINE LOSS ALLOCATORS
Seasonal Rate - Summer**

**SCHEDULE FCR-27
For the Period June-01-2026 - May-31-2028**

Line No.	Description	Line Loss Allocator (a)	FCR-27 Rate (b)	FCR-27 Rate By Voltage Level (Col. 3 X Col. 4)
(1)	(2)	(3)	(4)	(5)
1	Transmission Service	0.98259592	3.7846 ¢/kwh	3.7187 ¢/kwh
2	Primary Distribution	0.98949822	3.7846 ¢/kwh	3.7449 ¢/kwh
3	Secondary Distribution	1.00753619	3.7846 ¢/kwh	3.8131 ¢/kwh

(a) The line loss allocators from the Cost of Service study approved by the Commission in the 2022 base rate case.

(b) Exhibit____(ADH/MSB-4), Pg. 1, Line No. 8, Column 3

GEORGIA POWER COMPANY

**APPLICATION OF LINE LOSS ALLOCATORS
Seasonal Rate - Winter**

**SCHEDULE FCR-27
For the Period June-01-2026 - May-31-2028**

Line No.	Description	Line Loss Allocator (a)	FCR-27 Rate (b)	FCR-27 Rate By Voltage Level (Col. 3 X Col. 4)
(1)	(2)	(3)	(4)	(5)
1	Transmission Service	0.98259592	3.8335 ¢/kwh	3.7668 ¢/kwh
2	Primary Distribution	0.98949822	3.8335 ¢/kwh	3.7932 ¢/kwh
3	Secondary Distribution	1.00753619	3.8335 ¢/kwh	3.8624 ¢/kwh

(a) The line loss allocators from the Cost of Service study approved by the Commission in the 2022 base rate case.

(b) Exhibit____(ADH/MSB-4), Pg. 2, Line No. 8, Column 3

GEORGIA POWER COMPANY

Change in FCR Rates

SCHEDULE FCR-27

For the Period Jun-01-2026 - May-31-2028

Line No.	Description	Summer	Winter
<u>(1)</u>	<u>(2)</u>	<u>(3)</u>	<u>(4)</u>
	<u>FCR-27 Rate</u>		
1	Part A	3.6427 (a)	3.6924 (b)
2	Part B	0.1419 (c)	0.1411 (d)
3	Total	<u>3.7846</u>	<u>3.8335</u>
	<u>FCR-26 Rate</u>		
4	Part A	3.4274	3.1380
5	Part B	1.1259	1.1158
6	Total	<u>4.5533</u>	<u>4.2538</u>
	<u>Rate Change</u>		
7	Part A	0.2153	0.5544
8	Part B	<u>(0.9840)</u>	<u>(0.9747)</u>
9	Total	<u>(0.7687)</u>	<u>(0.4203)</u>

(a) Exhibit____(ADH/MSB-4), Pg. 1, Line No. 3, Column 3

(b) Exhibit____(ADH/MSB-4), Pg. 1, Line No. 6, Column 3

(c) Exhibit____(ADH/MSB-4), Pg. 2, Line No. 3, Column 3

(d) Exhibit____(ADH/MSB-4), Pg. 2, Line No. 6, Column 3

PUBLIC DISCLOSURE

Errata Exhibit___(ADH/MSB-7) Page
Docket No. 5GEORGIA POWER COMPANYCHANGE IN REVENUE BILLINGS
(Dollars in Thousands)SCHEDULE FCR-27
For the Period June-01-2026 - May-31-2028

Line No.	Description	Total	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Part A														
Summer & Winter														
1	Billed MWH Sales	70,825,491	REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED											
2	Change in Revenues	\$ 302,782												
Summer														
3	Billed MWH Sales	26,503,875	REDACTED REDACTED REDACTED REDACTED											
4	FCR-27 Part A less FCR-26 Part A	0.2153 (a)												
5	Change in Revenues	\$ 57,063												
Winter														
6	Billed MWH Sales	44,321,616	REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED											
7	FCR-27 Part A less FCR-26 Part A	0.5544 (b)												
8	Change in Revenues	\$ 245,719												
Part B														
Summer & Winter														
9	Billed MWH Sales	70,825,491	REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED											
10	Change in Revenues	\$ (692,801)												
Summer														
11	Billed MWH Sales	26,503,875	REDACTED REDACTED REDACTED REDACTED											
12	FCR-27 Part B less FCR-26 Part B	-0.984 (c)												
13	Change in Revenues	\$ (260,798)												
Winter														
14	Billed MWH Sales	44,321,616	REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED											
15	FCR-27 Part B less FCR-26 Part B	-0.9747 (d)												
16	Change in Revenues	\$ (432,003)												
Annual														
17	Part A	\$ 302,782												
18	Part B	(692,801)												
19	Total	\$ (390,019)												

(a) Exhibit___(ADH/MSB-6), Pg. 1, Line No. 7, Column 3

(b) Exhibit___(ADH/MSB-6), Pg. 1, Line No. 7, Column 4

(c) Exhibit___(ADH/MSB-6), Pg. 1, Line No. 8, Column 3

(d) Exhibit___(ADH/MSB-6), Pg. 1, Line No. 8, Column 4

Note: Details may not add to totals due to rounding

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For the Period Jun-01-2026 - May-31-2028

Note: Details may not add to totals due to rounding

GEORGIA POWER COMPANYEstimated Total Billed Sales
(MWh)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No.	DESCRIPTION	<u>Jun-26</u> (3)	<u>Jul-26</u> (4)	<u>Aug-26</u> (5)	<u>Sep-26</u> (6)	<u>Oct-26</u> (7)	<u>Nov-26</u> (8)	<u>Dec-26</u> (9)	<u>Jan-27</u> (10)	<u>Feb-27</u> (11)	<u>Mar-27</u> (12)	<u>Apr-27</u> (13)	<u>May-27</u> (14)
1	Residential	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	Commercial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	Industrial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	MARTA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
5	Street & Highway	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	Total FCR Applicable Sales	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Line No.	DESCRIPTION	<u>Jun-27</u> (15)	<u>Jul-27</u> (16)	<u>Aug-27</u> (17)	<u>Sep-27</u> (18)	<u>Oct-27</u> (19)	<u>Nov-27</u> (20)	<u>Dec-27</u> (21)	<u>Jan-28</u> (22)	<u>Feb-28</u> (23)	<u>Mar-28</u> (24)	<u>Apr-28</u> (25)	<u>May-28</u> (26)	TOTAL (27)
7	Residential	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	Commercial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	Industrial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	MARTA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
11	Street & Highway	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
12	Total FCR Applicable Sales	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	209,075,539

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANYEstimated FCR Applicable Sales
(MWh)SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028

Line No.	DESCRIPTION	<u>Jun-26</u>	<u>Jul-26</u>	<u>Aug-26</u>	<u>Sep-26</u>	<u>Oct-26</u>	<u>Nov-26</u>	<u>Dec-26</u>	<u>Jan-27</u>	<u>Feb-27</u>	<u>Mar-27</u>	<u>Apr-27</u>	<u>May-27</u>
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Residential	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
2	Commercial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
3	Industrial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
4	MARTA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
5	Street & Highway	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
6	Total FCR Applicable Sales	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

Line No.	DESCRIPTION	<u>Jun-27</u>	<u>Jul-27</u>	<u>Aug-27</u>	<u>Sep-27</u>	<u>Oct-27</u>	<u>Nov-27</u>	<u>Dec-27</u>	<u>Jan-28</u>	<u>Feb-28</u>	<u>Mar-28</u>	<u>Apr-28</u>	<u>May-28</u>	TOTAL
(1)	(2)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)
7	Residential	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
8	Commercial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
9	Industrial	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
10	MARTA	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
11	Street & Highway	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
12	Total FCR Applicable Sales	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED	143,524,387

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

**Calculation of Fuel Cost Recovery Rate
Seasonal Rate - Summer
(Dollars in Thousands)**

**SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028**

Line No.	Description	Amounts
(1)	(2)	(3)
1	Test Period Recoverable Fuel Costs for Part "A"	\$ 1,953,540
2	Test Period Estimated FCR Applicable Sales	<u>53,628,372 MWh</u>
3	Part "A" (Line 1 ÷ Line 2)	3.6427 ¢/kWh
4	FCR-27 Under-Recovery Part "B" including Carrying Costs	115,253
5	Estimated FCR Applicable Sales (3-Year Amortization)	<u>81,200,227 MWh</u>
6	Part "B" (Line 4 ÷ Line 5)	<u>0.1419 ¢/kWh</u>
7	Total Recoverable Fuel Costs (Line 1 + Line 4)	\$ 2,068,793
8	Total Average Fuel Rate (Line 3 + Line 6)	<u><u>3.7846 ¢/kWh</u></u>

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

**Calculation of Fuel Cost Recovery Rate
Seasonal Rate - Winter
(Dollars in Thousands)**

**SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028**

Line No.	Description	Amounts
(1)	(2)	(3)
1	Test Period Recoverable Fuel Costs for Part "A"	\$ 3,319,282
2	Test Period Estimated FCR Applicable Sales	<u>89,896,014 MWh</u>
3	Part "A" (Line 1 ÷ Line 2)	3.6924 ¢/kWh
4	FCR-27 Under-Recovery Part "B" including Carrying Costs	192,661
5	Estimated FCR Applicable Sales (3-Year Amortization)	<u>136,502,254 MWh</u>
6	Part "B" (Line 4 ÷ Line 5)	<u>0.1411 ¢/kWh</u>
7	Total Recoverable Fuel Costs (Line 1 + Line 4)	\$ 3,511,943
8	Total Average Fuel Rate (Line 3 + Line 6)	<u><u>3.8335 ¢/kWh</u></u>

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

**Adjustment for Prior Period Under-Recovery
(Dollars in Thousands)**

**SCHEDULE FCR-27
For the Period Jun-01-2026 - May-31-2028**

Line No.	Description	Total	Summer	Winter
<u>(1)</u>	<u>(2)</u>	<u>(3)</u>	<u>(4)</u>	<u>(5)</u>
1	Projected Under-Recovered Balance As of May 31, 2026	\$ 296,095		
2	Estimated mWh Applicable Sales	217,702,481	81,200,227	136,502,254
3	Percentage of Total Applicable Sales	100%	37.30%	62.70%
4	Projected Under Recovered FCR Balance	\$ 296,095	\$ 110,440	\$ 185,656
5	Recovery Per 12 month Period	\$ 98,698	\$ 36,813	\$ 61,885

Note: Details may not add to totals due to rounding.

GEORGIA POWER COMPANY

**APPLICATION OF LINE LOSS ALLOCATORS
Seasonal Rate - Summer**

**SCHEDULE FCR-27
For the Period June-01-2026 - May-31-2028**

Line No.	Description	Line Loss Allocator (a)	FCR-27 Rate (b)	FCR-27 Rate By Voltage Level (Col. 3 X Col. 4)
(1)	(2)	(3)	(4)	(5)
1	Transmission Service	0.98259592	3.7846 ¢/kwh	3.7187 ¢/kwh
2	Primary Distribution	0.98949822	3.7846 ¢/kwh	3.7449 ¢/kwh
3	Secondary Distribution	1.00753619	3.7846 ¢/kwh	3.8131 ¢/kwh

(a) The line loss allocators from the Cost of Service study approved by the Commission in the 2022 base rate case.

(b) Exhibit____(ADH/MSB-4), Pg. 1, Line No. 8, Column 3

GEORGIA POWER COMPANY

**APPLICATION OF LINE LOSS ALLOCATORS
Seasonal Rate - Winter**

**SCHEDULE FCR-27
For the Period June-01-2026 - May-31-2028**

Line No.	Description	Line Loss Allocator (a)	FCR-27 Rate (b)	FCR-27 Rate By Voltage Level (Col. 3 X Col. 4)
(1)	(2)	(3)	(4)	(5)
1	Transmission Service	0.98259592	3.8335 ¢/kwh	3.7668 ¢/kwh
2	Primary Distribution	0.98949822	3.8335 ¢/kwh	3.7932 ¢/kwh
3	Secondary Distribution	1.00753619	3.8335 ¢/kwh	3.8624 ¢/kwh

(a) The line loss allocators from the Cost of Service study approved by the Commission in the 2022 base rate case.

(b) Exhibit____(ADH/MSB-4), Pg. 2, Line No. 8, Column 3

GEORGIA POWER COMPANY

Change in FCR Rates

SCHEDULE FCR-27

For the Period Jun-01-2026 - May-31-2028

Line No.	Description	Summer	Winter
<u>(1)</u>	<u>(2)</u>	<u>(3)</u>	<u>(4)</u>
	<u>FCR-27 Rate</u>		
1	Part A	3.6427 (a)	3.6924 (b)
2	Part B	0.1419 (c)	0.1411 (d)
3	Total	3.7846	3.8335
	<u>FCR-26 Rate</u>		
4	Part A	3.4274	3.1380
5	Part B	1.1259	1.1158
6	Total	4.5533	4.2538
	<u>Rate Change</u>		
7	Part A	0.2153	0.5544
8	Part B	(0.9840)	(0.9747)
9	Total	(0.7687)	(0.4203)

(a) Exhibit____(ADH/MSB-4), Pg. 1, Line No. 3, Column 3

(b) Exhibit____(ADH/MSB-4), Pg. 1, Line No. 6, Column 3

(c) Exhibit____(ADH/MSB-4), Pg. 2, Line No. 3, Column 3

(d) Exhibit____(ADH/MSB-4), Pg. 2, Line No. 6, Column 3

GEORGIA POWER COMPANYCHANGE IN REVENUE BILLINGS
(Dollars in Thousands)SCHEDULE FCR-27
For the Period June-01-2026 - May-31-2028

Line	No.	Description	Total	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Jan-27	Feb-27	Mar-27	Apr-27	May-27
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Part A														
	Summer & Winter														
1	Billed MWH Sales	70,825,491	REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED												
2	Change in Revenues	\$ 302,782													
	Summer														
3	Billed MWH Sales	26,503,875	REDACTED REDACTED REDACTED REDACTED												
4	FCR-27 Part A less FCR-26 Part A	0.2153 (a)													
5	Change in Revenues	\$ 57,063													
	Winter														
6	Billed MWH Sales	44,321,616	REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED												
7	FCR-27 Part A less FCR-26 Part A	0.5544 (b)													
8	Change in Revenues	\$ 245,719													
	Part B														
	Summer & Winter														
9	Billed MWH Sales	70,825,491	REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED												
10	Change in Revenues	\$ (692,801)													
	Summer														
11	Billed MWH Sales	26,503,875	REDACTED REDACTED REDACTED REDACTED												
12	FCR-27 Part B less FCR-26 Part B	-0.984 (c)													
13	Change in Revenues	\$ (260,798)													
	Winter														
14	Billed MWH Sales	44,321,616	REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED REDACTED												
15	FCR-27 Part B less FCR-26 Part B	-0.9747 (d)													
16	Change in Revenues	\$ (432,003)													
		Annual													
17	Part A	\$ 302,782													
18	Part B	(692,801)													
19	Total	\$ (390,019)													

(a) Exhibit___(ADH/MSB-6), Pg. 1, Line No. 7, Column 3

(b) Exhibit___(ADH/MSB-6), Pg. 1, Line No. 7, Column 4

(c) Exhibit___(ADH/MSB-6), Pg. 1, Line No. 8, Column 3

(d) Exhibit___(ADH/MSB-6), Pg. 1, Line No. 8, Column 4

1 MS. PRYOR: Chairman Shaw, with your
2 permission, I'd like Mr. Houston to summarize the
3 prefiled direct testimony of the panel.

4 CHAIRMAN SHAW: Go ahead, Mr. Houston.

5 MR. HOUSTON: Oh, thank you, Commissioners.
6 Good morning.

7 CHAIRMAN SHAW: Good morning.

8 MR. HOUSTON: We appreciate the opportunity
9 to appear today in support of Georgia Power
10 Company's 27th Fuel Cost Recovery Application.
11 We're here today because the Commission's May 21st,
12 2023, order adopting stipulation of the FCR-26 case
13 required the company to file new FCR rates on or
14 before February 28th, 2026. The company filed its
15 application and supporting minimum filing
16 requirements, or MFRs, on February 17th, 2026, in
17 compliance with that order.

18 With this application, the company is
19 proposing to adjust its current fuel rates to an
20 appropriate level to recover the company's future
21 fuel costs and projected under-recovery from
22 FCR-26. This under-recovery is based on
23 projections for the two-year FCR-27 test period
24 from June 1st, 2026, to May 31st, 2028.

25 Although the majority of the prior

1 under-recovery period is projected to be collected
2 by May 31st, 2026, the company proposes to recover
3 the remaining under-recovered balance over a
4 three-year period. The proposed FCR-27 rate
5 changes, as revised by the errata filed last week,
6 are projected to decrease the monthly bill for a
7 typical residential customer using
8 1,000 kilowatt-hours per month by approximately
9 \$5.78.

10 Together with the Commission's storm damage
11 recovery application, which is being considered by
12 the Commission concurrently with this application,
13 we expect to have typical residential customer
14 bills to decrease by \$1.37 per month.

15 Consequently, the company will lower rates
16 for customers as a result of this request in this
17 case. This request follows the remarkable load
18 growth coming to the state that will create
19 additional downward pressure on rates and continues
20 the momentum from Georgia Power's base rate freeze
21 approved in 2025.

22 Additionally, the company is recommending the
23 interim fuel recovery, or IFR, threshold from 200
24 to 300. Consistent with the current IFR, the
25 300 million will be applied in either direction of

1 the over- and under-recovery balance. As proposed,
2 the currently approved maximum 40 percent of
3 cumulative rate change will remain unchanged, along
4 with the timing and filing requirements. The
5 proposed modification will better align the IFR
6 threshold to the magnitude of the total fuel
7 expenses annually incurred by the company. This
8 will, in turn, provide greater rate stability for
9 customers by allowing FCR rates to absorb natural
10 fuel price volatility and fluctuations on a monthly
11 basis.

12 The company also proposes to expand its
13 natural gas hedging program by increasing both the
14 percentage and budgeted burn that may be hedged
15 from 40 percent to 60 percent, as well as the
16 length of the hedging window from 36 months to
17 48 months. The current hedging program works as
18 intended -- as intended to mitigate price
19 volatility and continues to provide benefits to
20 customers. However, these proposed changes are
21 warranted given the projected growth and natural
22 gas burn in the company's budget. By enhancing the
23 scope of the hedging program, the company will
24 better be positioned to mitigate price exposure and
25 avoid greater stability and fuel costs for the

1 benefit of our customers.

2 Finally, the company requests continued
3 authorization to recover the costs and revenues
4 from renewable requests for proposals, or RFPs, and
5 customer renewable programs through the fuel
6 clause, consistent with past practice.

7 The company currently collects bid fees and
8 winners' fees under its RFPs to help defray certain
9 costs associated with the developing and running
10 the RFP. Where the RFP fees do not cover the full
11 costs associated with the company's renewable RFPs,
12 the company recovers the remainder through the fuel
13 clause. The benefits of renewable energy procured
14 through RFPs accrue to customers in the form of
15 lower fuel costs over time. Therefore, it is
16 appropriate to recover the costs associated with
17 procuring these renewable resources through the FCR
18 where the benefit to customers accrue.

19 In closing, we note that the company is not
20 proposing a specific date for its next fuel case
21 and proposes to continue semiannual reporting of
22 relevant fuel information through the FCR-27 test
23 period to ensure fuel costs are recovered as
24 expected. On the whole, the company's request in
25 this case will provide flexibility, it will allow

1 the company and Commission to timely and
2 effectively respond to potential fuel price
3 volatility, and avoid the need for formal deferral
4 orders if future circumstances show that the fuel
5 rates approved in this case are sufficient.

6 We appreciate your time and welcome your
7 questions.

8 MS. PRYOR: Thank you.

9 Chairman Shaw, the panel is now available for
10 questions from Commissioners, as well as
11 cross-examination.

12 CHAIRMAN SHAW: Thank you.

13 Commissioners.

14 COMMISSIONER HUBBARD: I'd like to start out
15 with a few questions, if I can.

16 MR. HOUSTON: Sure.

17 COMMISSIONER HUBBARD: Your testimony states
18 that they're increasing fuel expenses from --
19 driven by higher load requirements. Who really is
20 behind those higher load requirements?

21 What I'm trying to get at is that we are --
22 you're proposing to expand both the hedging budget
23 and the interim fuel rider on the grounds that
24 there's going to be higher volatility, there's
25 going to be higher load requirements, effectively.

1 And so what I'm trying to understand is, from
2 your viewpoint, who is driving those higher load
3 requirements. And are those costs being borne by
4 those driving higher load requirements or are we
5 socializing these costs of higher IFR proposed,
6 higher hedging budget across all customers, rather
7 than those that are causing this request?

8 MR. HOUSTON: Yeah. That's a -- that's an
9 excellent question. A lot of -- a lot of points
10 and a lot of very important points, Commissioner.

11 So, you're right, load is increasing over the
12 test period for the next two years. Perhaps
13 some -- at least 98 percent of that is coming from
14 commercial and industrial companies, and about
15 2 percent of that is coming from residential.

16 So a lot of that is coming from the RTP
17 customers, large load customers, manufacturing
18 moving into the state. And then, you know, there's
19 also some data center in megawatts in there also.

20 So most of that load -- or the vast majority
21 of that load is coming from growth in the state of
22 Georgia. So large manufacturing, data centers and
23 just other growth opportunities to the state.

24 COMMISSIONER HUBBARD: Yeah. And I guess the
25 second part of my question is: 98 percent is being

1 driven by large commercial industrial customers,
2 but we're seeing increased demand, which will
3 increase the -- the cost of this fuel. The
4 projected fuel costs are higher than the
5 historical. And I'm just trying to wrap my arms
6 around whether or not those costs are being borne
7 by those that are causing them.

8 Since we're now seeing higher demand, we're
9 seeing higher proposed hedging, IFR. That's --
10 that's the question I'm trying to get at is: Are
11 you accounting for those higher costs that are
12 going to be borne by all customers, even though --

13 MR. HOUSTON: Yes.

14 COMMISSIONER HUBBARD: -- 98 percent are in
15 one bucket?

16 MR. HOUSTON: Yes. I mean, absolutely. I
17 mean, this -- this large load is growth in the
18 state of Georgia. And this large load has enabled
19 us to enter into the rate freeze that was signed
20 last year in the IRP stipulation. So we are
21 currently in a rate freeze right now. So the rest
22 of 2026, all of 2027, and 2028 there will be no
23 rate increase. So that's the rate freeze.

24 It's also enabled us to put downward pressure
25 on rates starting in 2029 the way that we're going

1 to lock in some revenues in the 2028 rate case. So
2 I would say, yeah, large load coming to the state.
3 That's growth in the state of Georgia.

4 And we are seeing the benefits already with
5 that growth coming in and the commitments we made
6 around rate freeze and the commitments we made
7 about putting downward pressure on rates to the sum
8 of about \$1.6 billion that will be put into the
9 next rate case as a minimum revenue.

10 COMMISSIONER HUBBARD: Okay. Thank you.

11 One or two just basic questions. I heard you
12 mention the 1,000 kilowatt-hours, the typical
13 customers.

14 MR. HOUSTON: Yes.

15 COMMISSIONER HUBBARD: That's really the
16 typical customer or what is the average typical
17 customer consuming on a monthly basis?

18 MR. HOUSTON: No. That's -- that's also
19 another great question. I -- that's what we use is
20 a standard 1,000 kilowatt-hours per month. And
21 that obviously has a load shape. So some months
22 it's higher, some months it's lower.

23 Subject to check, I do remember reading
24 somewhere that maybe the average kilowatt-hour
25 usage for a residential customer in the U.S. is

1 something between 800 and 900 kilowatt-hours.

2 So I think 1,000 kilowatt-hours is the
3 standard we use. And I think that works well when
4 we talk about the rate impacts for customers. So I
5 don't -- I don't -- I wouldn't say that that's out
6 of the ordinary or particularly high or
7 particularly low. I think it's appropriate. And
8 it's what we've -- we have done for many years,
9 talked about the typical residential customer.

10 COMMISSIONER HUBBARD: If it's below that
11 threshold of 1,000 kilowatt-hours, then the -- the
12 overall customer bill would be lower. It would
13 keep it to the first two tiers up to
14 1,000 kilowatt-hours. If it's above that, and it
15 is in Georgia, it's around 1,080 kilowatt-hours,
16 then actually the numbers that you threw out would
17 be a little bit higher if this proposal is accepted
18 as given.

19 But I just wanted to -- to state for the
20 record that it is higher than 1,000 kilowatt-hours.
21 It's closer to 1,080 in Georgia, according to a
22 couple different sources.

23 How much -- what percentage of the fuel that
24 we're talking about here -- coal, gas, uranium --
25 how much of that is sourced here in Georgia?

1 MR. HOUSTON: I don't have that number off
2 the top of my head. But just thinking about what
3 we have, I would say the majority with the nuclear
4 fleet. Clearly, the largest renewable source in
5 the country, over 4,000 megawatts at Plant Vogtle.
6 So I don't have an exact number, Commissioner, but
7 I would say the majority.

8 COMMISSIONER HUBBARD: I'm always interested
9 in economic development in the state. And I'm
10 fairly certain that most of the gas and the coal
11 comes from out of state, rather than keeping those
12 dollars here in Georgia.

13 MR. HOUSTON: Yes. Well -- well, Plant
14 Bowen, obviously, which is over 3,000 megawatts, is
15 just north of Atlanta. So that is, as I'm sure you
16 know, located in the state of Georgia.

17 COMMISSIONER HUBBARD: So I wanted to check
18 in on coal because you just mentioned Bowen; right?
19 And I didn't hear that in the summary, but it's in
20 the testimony.

21 On page 10 of the rebuttal, there's a mention
22 of diversity of supply sources being a benefit.
23 Does that same diversity of generation resources
24 also extend?

25 Is diversity, generally speaking, a good

1 thing?

2 MR. HOUSTON: Yeah. If your question is
3 about generation mix, I think that our fleet would
4 be the envy of many utilities around the country,
5 between nuclear, solar fleet, we're building a lot
6 of batteries coming up, coal, natural gas. I mean,
7 I think we have all of the above strategy.

8 So I think diversity is very important and
9 gives us a lot of flexibility. If your question
10 was about the generation fleet or was it about the
11 coal?

12 COMMISSIONER HUBBARD: Just about diversity
13 in general. There's a mention of diversity of
14 supply sources being of a benefit. And I was
15 asking if that extends to generation resources and
16 just diversity in general.

17 MR. HOUSTON: Yeah. One -- one thing I would
18 point out on the diversity of generation, if you
19 add up our nuclear generation -- this is for the
20 test period -- add up the nuclear generation for
21 the test period, the solar, hydro, and then the
22 renewable PPAs, that actually has more generation
23 than any of the natural gas generation we have.

24 So I know there's a lot of discussion about
25 natural gas and the increased exposure to that.

1 But if you look at even for the next two years what
2 the generation mix is and where the -- the
3 megawatts are coming from, there's actually more
4 from those three sources than there is from the
5 nuclear gas generation.

6 COMMISSIONER HUBBARD: Right. Yeah. But
7 you're talking about in this test period in the
8 next few years. Is that -- that'll take time for
9 the new certified resources to come online and then
10 that dynamic will change, I think, from 2031
11 onwards?

12 MR. HOUSTON: Yes.

13 COMMISSIONER HUBBARD: But just to follow up
14 on the diversity of supply sources, I noticed that
15 there was a mention of the diversity of supply
16 sources with respect to coal contracts. But a lot
17 of those coal contracts would come with minimum
18 delivery requirements.

19 So isn't diversifying the number and type of
20 coal contracts kind of tying you to a minimum
21 delivery that then is a lack of flexibility on the
22 part of the company?

23 MR. HOUSTON: Yeah. I mean, that's -- that's
24 an excellent question and something that we -- we
25 obviously monitor and manage. I would just point

1 out that one of the panel mates in rebuttal, he is
2 here to talk about coal contracting.

3 COMMISSIONER HUBBARD: Okay.

4 MR. HOUSTON: And questions you have about
5 minimums and coal contracts and diversity of
6 supply, he can answer those questions.

7 COMMISSIONER HUBBARD: Okay. And also
8 questions on coal dispatch?

9 MR. HOUSTON: Yes. Yes, sir.

10 COMMISSIONER HUBBARD: Okay. And also -- I
11 mean, you did mention the hedging, though. Did
12 you -- I was curious in the -- in the rebuttal, I
13 didn't really see a justification for that
14 expansion of the hedging beyond just we're entering
15 into a period of higher price volatility with
16 increased scarcity in the gas market. My
17 question -- where did it go?

18 Yeah. I didn't see in the rebuttal
19 testimony. I mean, what I did see, though, in
20 staff testimony -- and we'll talk about this, but
21 maybe you could address it.

22 I saw 17 years of losses on the hedging
23 program with only four years of benefit. And so
24 I'm struggling to -- to understand the
25 justification for expanding that volatility when

1 it's been a money loser, it's fair to say, over the
2 last 20 years, and especially in the last three
3 years.

4 MR. HOUSTON: Yeah. I mean, we certainly
5 don't characterize it like that. And it depends on
6 the time series you look at.

7 If you -- in staff's testimony, if you look
8 at that table and you look at the most recent
9 eight, nine, ten years, there's actually been a
10 gain on hedges, with significant hedge gains when
11 we needed it the most during 2022. You know,
12 during the -- during the war of Ukraine/Russia. So
13 we had something in the vicinity of over
14 \$200 million of hedge gains.

15 But looking at that number, isn't the point
16 for us with -- with hedges. Clearly we like to
17 have gains, but we think of it as a risk
18 management-type instrument and really insurance and
19 really to protect the customers from sudden spikes
20 in natural gas price.

21 So, you know, we think of it as just prudent
22 risk management, something you should have, and a
23 real risk that's out there that needs to be
24 managed. So whereas staff suggests that we take
25 that down to 0 percent, we disagree. And we think

1 taking a known risk and basically having it
2 unmanaged is not prudent.

3 So for us it's a -- it's a question of
4 managing a risk and also acknowledging that natural
5 gas, we are going to burn more of that coming up.
6 So this is just a balance of all the factors. And
7 we -- we thought 60 percent was a good place to be.

8 But we just think that -- like with anything,
9 any good financial practice, whether it's portfolio
10 management or having insurance, if you have
11 insurance, that's a good practice. If you don't
12 need to -- to draw down insurance because nothing
13 bad happened, that's not necessarily a bad thing,
14 so...

15 COMMISSIONER HUBBARD: Yeah. And just to
16 follow up on that --

17 COMMISSIONER JOHNSON: I have a --

18 COMMISSIONER HUBBARD: Oh, sorry. Just a
19 moment.

20 There -- there are more mechanisms than just
21 hedging to be able to mitigate that rate
22 stability -- rate volatility, I should say. And
23 one of those tools is in a fuel cost recovery
24 docket to be able to amortize costs over a period
25 of time, that sort of thing.

1 So, I guess, do you have an opinion on the
2 cost effectiveness of the hedging program versus
3 simply the carrying costs of amortizing or
4 securitizing debt over time?

5 MR. HOUSTON: Yeah. I think what we have --
6 I think the hedge program that we have has worked
7 effectively. And I acknowledge there are some
8 years where you have hedge losses, but we had gains
9 when we needed them the most.

10 And I think that's worked effectively. And I
11 think the expansion that we're -- we're requesting
12 from this Commission I think just puts even more
13 protections on for customers.

14 And, you know, I would say, you know, we --
15 we do have an under-recovered balance going into
16 this case. And we consider amortization periods.
17 And in this case, we're -- we're asking the
18 Commission for approval of a three-year recovery
19 period. So that's -- that's a pretty extended
20 recovery period. So we look at all of those facts,
21 yes.

22 COMMISSIONER HUBBARD: Okay. Thank you.

23 Commissioner Johnson or anyone else?

24 COMMISSIONER JOHNSON: I just want to go back
25 and clarify something as we were talking about the

1 overall risk and pass-through of the fuel cost.
2 Can you clarify or confirm that the company really
3 bears no direct financial risk from fuel price
4 increases and that those are 100 percent passed on
5 to the customer?

6 MR. HOUSTON: Yes. The fuel costs are
7 dollar-for-dollar recovery and they are a
8 pass-through. There are no earnings associated
9 with the fuel costs at all.

10 Every day on a daily basis as a -- as a
11 company, as a series of professionals around the
12 company, we are looking to minimize fuel case. So
13 there may be people in the power plants working on
14 improving heat rate, that may be dispatch, that may
15 be operations. So many people are involved.

16 I -- I would say that with the fuel cost,
17 customers pay no more than the incurred cost. So
18 there's -- there's no added to that. There's
19 nothing additional. To the extent that estimates
20 differ from actuals, customers only pay what the
21 actual costs were.

22 COMMISSIONER JOHNSON: Okay. And so a cost
23 sharing would require, though, the company to bear
24 a portion of the fuel risk; correct?

25 MR. HOUSTON: Yes. I've heard of the

1 cost-sharing mechanisms out there in different
2 states, which we don't -- we don't have in Georgia.
3 I'm not aware there are any in the southeast. And
4 I think it probably depends on how they're being
5 constructed.

6 But I think in principle, that's sort of the
7 thinking and the theory behind cost-sharing is that
8 the company would -- there would be some sharing,
9 some percentage, less than 100 percent, that the
10 company would have to manage to.

11 VICE CHAIRMAN MCDONALD: What does the law
12 say?

13 MR. HOUSTON: The law say on cost sharing?

14 VICE CHAIRMAN MCDONALD: The law say on the
15 fuel recovery.

16 MR. HOUSTON: The law on the fuel recovery is
17 a statute, which was -- I think came out in the
18 1970s that say we get dollar-for-dollar recovery
19 and this Commission has authority to assess it for
20 prudence. And so that's where the Commission's
21 authority is. And that's the statute and the law
22 of Georgia.

23 COMMISSIONER JOHNSON: Yeah. So the current
24 statute, again, was written in the '70s and just
25 may be out of best practice.

1 But my next question is: The company has
2 highlighted a decrease in our -- in our consumer
3 bills. Has -- is some of that decrease partly due
4 to prior cost recovery rolling off?

5 MR. HOUSTON: Yes, it is, Commissioner.

6 COMMISSIONER JOHNSON: Okay.

7 MR. HOUSTON: Yes.

8 COMMISSIONER JOHNSON: So -- so the bill
9 decrease does not reflect the lower current fuel
10 cost; just the prior -- the prior roll off?

11 MR. HOUSTON: Yeah.

12 MR. BERRIGAN: So -- so, Commissioner, to
13 clarify, there's two components to the -- to the
14 fuel cost recovery. You have your Part A and your
15 Part B; right?

16 COMMISSIONER JOHNSON: Uh-huh.

17 MR. BERRIGAN: So thinking about Part B,
18 that's kind of the amortization of previously
19 incurred amounts. I believe that's what you're
20 speaking to.

21 In FCR-26, there was a large under-recovered
22 balance, approximately 2.2 billion. And that's
23 been -- the customers have been paying that down
24 over the last three years and that will be paid off
25 by the end of FCR-26.

1 And so that -- that goes away. There's a
2 current Part B -- right? -- which is the over- or
3 under-recovery balance that has built up throughout
4 FCR-26. That becomes the new Part B, which, as
5 Mr. Houston said, will -- we're proposing to
6 amortize over three years. And then you replace
7 Part A with the new fuel rate for future costs;
8 right? So what we're projecting our costs to be
9 over the -- the test period.

10 And so that projection of future costs is
11 going up. So, you're right, on a net basis we have
12 a decrease. Part of that is because Part B has
13 gone down. Part of that is that offset by Part A
14 going up. But net/net, it's a decrease in rates.

15 COMMISSIONER JOHNSON: Okay. Thank you.

16 VICE CHAIRMAN MCDONALD: What would we --
17 what would we be looking at if we didn't have
18 Unit 3 and Unit 4 at Plant Vogtle?

19 MR. HOUSTON: Well, that's a great question,
20 Commissioner. I mean, those -- those units are
21 very efficient. And if you look at one of the
22 tables here, on a dollar per megawatt-hour -- I
23 don't have it exactly, but it's possibly less than
24 \$10. So it's cheaper than all other sources. So
25 we would be looking at less of a decrease or

1 possibly even an increase.

2 CHAIRMAN SHAW: Most of my questions were
3 around hedging. And I think y'all have done a good
4 job of answering Commissioner questions on that.

5 But, I mean, I'll just kind of reiterate
6 what's been said. You know, staff's recommendation
7 to do away with the hedging program, I mean -- you
8 don't even have to respond because you already
9 have. But it's just -- you know, we're not getting
10 a return for it. The costs outweigh the benefits.
11 And so maybe perhaps there is a way to keep, like
12 you mentioned, the insurance portion without
13 finding a way to make it better.

14 My question would be around the -- you know,
15 the company does not propose setting a date for the
16 next fuel case. And it's traditionally a
17 three-year cycle. What is your -- what is your
18 reasoning behind not going ahead and -- and setting
19 a date for the next case?

20 MR. HOUSTON: Yeah.

21 MR. BERRIGAN: And we're not opposed to
22 setting a date. I think as we look through and
23 we're looking at the -- the proposals in this
24 case -- right? -- with a two-year test period,
25 three-year amortization of the under-recovered

1 balance -- the previous under-recovered balance,
2 you know, our -- in our original proposal, we just
3 thought that it would be best to -- to not set a
4 date -- a defined date.

5 And as Mr. Houston said, we have monthly and
6 quarterly reporting that we do to the Commission
7 and would continue to monitor that as we go forward
8 and set a date in the future for the next
9 proceeding. But we're not opposed to setting one,
10 if that's what the Commission would -- would
11 propose doing.

12 CHAIRMAN SHAW: Okay. Any other questions?

13 COMMISSIONER HUBBARD: Just a follow-up. So
14 help me understand this two-year test period, but
15 three-year amortization period, and an undefined
16 date so far. Why is that?

17 And I notice that the projected third year
18 fuel costs are quite a bit higher than the first
19 and second year. So help me understand why you're
20 proposing that two-year test period.

21 MR. BERRIGAN: So a two-year test period is
22 a -- two-year test period is kind of more of the
23 traditional test period that we've had. If you go
24 back to the last couple of FCRs, we usually propose
25 a two-year test period.

1 When looking at amortization of the
2 previously under-occurred -- under-recovered
3 balance, we determined that stretching that out for
4 a third year, as we did in FCR-26, was going to
5 have a -- obviously a lower impact for customers.

6 Thinking about rate impacts, we felt like it
7 was better to stretch that previously
8 under-recovered balance out an additional year.
9 But the two-year test period is -- again, that's
10 consistent with the last couple of FCR filings.

11 COMMISSIONER HUBBARD: If your projections
12 are correct, though, and the third year fuel costs
13 are substantially higher than the first two years,
14 and we also have that amortization pancaked onto
15 that, aren't we kind of setting ourselves up for
16 some fairly high fuel costs in year three?

17 MR. BERRIGAN: Possibly; right? I mean,
18 those are projections of what fuel costs will do in
19 the future. And, again, that's where I think our
20 proposal of not setting the next case -- right? --
21 that would give us the opportunity to monitor and
22 kind of look at where those costs are going.

23 And to the extent that -- that they are
24 increasing, that would, you know, allow the company
25 to -- and the Commission to ultimately determine

1 for the company to come back in something less than
2 three years for the next proceeding.

3 COMMISSIONER HUBBARD: And just the last
4 question I have is: I know that Georgia Power
5 Company says that they don't profit from this.
6 This is a pass-through. And I -- that's subject to
7 check.

8 And I know that I asked Commission advisory
9 staff for an opinion on that and I'm expecting that
10 at the end of the hearings. But are any companies
11 affiliated with Georgia Power Company earning a
12 return on fuel costs?

13 MR. HOUSTON: Certainly we have transactions
14 with Southern Power, which is our sister company,
15 primarily through PPA arrangements. But, you know,
16 there are pretty strict rules that govern what
17 those arrangements are.

18 So every time we enter into a power purchase
19 agreement with Southern Power, that does need to go
20 to FERC. So FERC will go through and review
21 affiliated transaction. The Commission always has
22 jurisdiction over that, as well, and they, I
23 believe, look at those transactions.

24 So I think there's many checks and balances
25 in place to make sure there's -- that the contracts

1 are not manipulated in any way.

2 MR. BERRIGAN: And from an electric
3 perspective, Alabama Power, Mississippi Power, I'm
4 not familiar with exactly their -- their
5 cost-recovery mechanisms. But, again, as
6 Mr. Houston said, I know that affiliate
7 transactions are required; right?

8 We have to bring all of those to the
9 Commission. We needed Commission approval before
10 we can enter into those. And then subsequent to
11 that, FERC approval. So, again, kind of two levels
12 of review to ensure that the costs are appropriate
13 in those transactions.

14 MR. HOUSTON: Yeah. And I would just say,
15 coming out of the last -- one of the prior
16 certifications, we still have some PPAs pending in
17 front of FERC for approval. So they're certainly
18 there. And they certainly go through the process.

19 CHAIRMAN SHAW: All right. Any other
20 questions?

21 (No response.)

22 We'll move on, starting with cross with
23 Georgia Public Service Commission.

24 MR. COLLADO: Good morning, Commissioners.

25 CHAIRMAN SHAW: Good morning.

1 MR. COLLADO: Good morning, panel.

2 MR. BERRIGAN: Good morning.

3 CROSS-EXAMINATION

4 BY MR. COLLADO:

5 Q. Mr. Houston, in response to Commissioner
6 Hubbard's question, you stated that a large part of the
7 new additional burn is attributed to the incremental new
8 load coming onboard; correct?

9 A. (Witness Houston) Yes.

10 Q. And you also stated that it -- a significant
11 amount of that load will be an RTP tariff. In fact, you
12 actually gave a percentage.

13 What was that percentage again?

14 A. (Witness Houston) So we have in the test
15 period an increase of approximately 36 million
16 megawatt-hours as the increase. 34.9 of that relates to
17 commercial and industrial customers.

18 Q. 34.9 of 36; correct?

19 A. (Witness Houston) Yes.

20 Q. Is on the RTP?

21 A. (Witness Houston) Yes.

22 And just -- just to clarify, they're not
23 necessarily all on the RTP, but many of the larger ones
24 are on the RTP.

25 Q. Okay. But it's -- you would agree that a

1 significant amount of it is on RTP?

2 A. (Witness Houston) Yes, I would.

3 Q. Okay. And the RTP tariff has an incremental
4 fuel charge component; correct?

5 A. (Witness Houston) Yes.

6 Q. Isn't it true that RTP customers who pay the
7 incremental fuel charges are required to pay market fuel
8 costs, which reflects the volatility of the natural gas
9 markets?

10 A. (Witness Houston) Yes. RTP customers,
11 their -- their fuel contribution reflects the marginal
12 costs incurred by the company to serve those customers on
13 an hour-to-hour basis.

14 Q. Okay. So if the RTP customers are already
15 paying the costs that reflect the volatility of the fuel
16 market, and the RTP customers are currently driving the
17 new increment -- the incremental fuel burn, the new fuel
18 burn, why does the company believe it's desirable to
19 increase the amount of hedging performed when the hedging
20 will incur costs on all customers?

21 A. (Witness Houston) Well, we hedge -- as a
22 portfolio and our proposal is 60 percent hedging. That's
23 the cost. We're hedging the cost -- right? -- of
24 purchasing the natural gas. And we just think it's a
25 prudent risk management strategy. And we think it's not

1 prudent at all to leave it completely unmanaged.

2 Q. And Commissioner Hubbard also pointed out
3 that there was losses on most -- or there is usually
4 losses on the hedging program. But, in response, you
5 stated that the last eight to ten years had actually
6 posted gains; correct?

7 A. (Witness Houston) Yeah. I think I used that
8 eight-year period. If you've just cumulatively --
9 cumulatively added up each of the years, it is a net gain.

10 Q. Okay. Cumulatively, would you agree, subject
11 to check, that the hedging program has led to losses of
12 273 million since FCR-26?

13 A. (Witness Houston) Sorry. Can you repeat the
14 question?

15 Q. Yes. You mentioned cumulatively those
16 losses. Would you agree, subject to check, that the
17 hedging program has led to losses of \$273 million since
18 FCR-26 was filed?

19 A. (Witness Houston) Can you show me where that
20 is?

21 Q. It is mentioned in staff's testimony.

22 A. (Witness Houston) Yeah. I do remember
23 seeing that. I just don't remember the numbers exactly.

24 Q. Yep. I also don't remember the exact page
25 number, so...

1 A. (Witness Houston) Well, let me just -- let
2 me just say that you -- you will have periods where you
3 have hedge gains and you will have periods where you have
4 hedge losses. So if you pick a short period, you know, it
5 could be gains or losses.

6 So, you know, the -- our objective is to have
7 a risk management methodology in place that protects the
8 customers from spikes when they happen. And we just don't
9 know when those spikes are going to happen. So that's why
10 we layer in these hedges for the benefit of customers.

11 Q. Understood.

12 And let's -- let's focus on the time period
13 that you mentioned, the last ten years. And in rebuttal
14 you said that the hedge positions over the last ten years
15 have resulted in a cumulative gain over the time period,
16 consistent with what your testimony is right now; correct?

17 A. (Witness Houston) Yes.

18 Q. Okay. Yes. But he also said that during his
19 testimony now about ten years.

20 So you're saying that the hedging performance
21 of the last ten years was an improvement over the previous
22 ten years; correct?

23 A. (Witness Houston) I'm saying if you look at
24 the most recent series of years, it was a gain. And if
25 you go back through a longer period, I think maybe there

1 was a loss.

2 But a lot has happened in the natural gas
3 market. So it's -- it's not really valid to go back and
4 look at 20, 25 years and sum those up and draw any
5 conclusion from what a current hedge program will result.

6 A. (Witness Berrigan) And then to add to that, I
7 mean, there's certainly been changes in the market
8 fundamentals over the last 25 years. If you think about
9 the introduction of the shale gas revolution, fracking,
10 you go back to -- I think stats table starts in kind of
11 the mid 2000s. And you really go back, right around 2010,
12 I think, is when that shale gas revolution started --
13 started producing much cheaper natural gas prices.

14 And so as those prices have come down -- and
15 that's why, you know, when Mr. Houston says, "Look at the
16 more recent ten-year history as opposed to going back
17 25 years and looking again," it's taking into
18 consideration that it's a -- kind of a completely
19 different natural gas market today than it was 25 years
20 ago.

21 And so, again, over the more recent horizon,
22 not looking at one year, two years, three years, but kind
23 of looking over the last ten years as -- as the natural
24 gas market has kind of been consistent. And it has
25 ultimately over those ten years -- it's roughly had a

1 small -- a small gain.

2 A. (Witness Houston) And I'd just like to add.
3 Just looking at hedge gains and losses in isolation
4 doesn't really tell you the full story. Because the flip
5 side of a hedge loss is low natural gas prices. And
6 customers benefit from low natural gas prices.

7 So it's just a risk management tool. If you
8 have hedge losses, that means natural gas prices are
9 lower. And we're not hedging 100 percent. So there are
10 benefits going through in that unhedged portfolio.

11 Q. And you mentioned that there was changes in
12 the natural gas market over the last 20 years that could
13 be influencing that analysis. But isn't it also true that
14 there has been changes in the hedging program over the
15 last -- or within the last ten years, too; correct?

16 A. (Witness Houston) Yes. I understand that
17 through various FCR's, hedging percentages have gone up
18 and down and the hedging window has changed. So, yes.

19 Q. Okay. Isn't it possible that the better
20 performance over the last ten years could be attributed to
21 the fact that the Commission revised the hedging limits by
22 shortening the hedging window and reducing the allowed
23 hedging volumes in May of 2020?

24 A. (Witness Houston) I mean, that's -- that's a
25 little bit speculative and a -- sort of a

1 counter-narrative. Certainly in times where prices are
2 going up that you have more hedges on, then you'll have
3 more gains.

4 If we had 60 percent hedge limitation during
5 2022, our gains would have been substantially better. So,
6 I guess, mathematically, that is correct.

7 Q. So you believe that a higher hedging window
8 after 2020 would have made it even bigger gains for the
9 company or -- if it's too speculative, I'm not trying to
10 put you --

11 A. (Witness Houston) Well, I mean, it is very
12 speculative. I mean, we all know natural gas markets
13 are -- can change rapidly. And so that -- that's what
14 people said.

15 We had a 40 percent hedge limit. That's what
16 the Commission thought was appropriate at the time.
17 That's what we were working to. And that -- that was
18 appropriate at the time because that's what the Commission
19 approved.

20 A. (Witness Berrigan) And just to clarify, I
21 think you said that would result in higher hedge gains for
22 the company. It has no impact on the company; right?

23 It's -- again, hedge gains and losses go
24 through the -- the FCR. They're part of the fuel cost
25 recovery mechanism. And so there's no gains or losses

1 that the company has any part in.

2 Q. Correct. But I was just pointing out that
3 the hedging losses were higher when the hedging was higher
4 before 2020.

5 And now I understand there's a lot of factors
6 that go into this. I was just pointing that out. That is
7 true; correct?

8 A. (Witness Houston) I think that you can
9 deduce that mathematically. But hedging programs are very
10 dynamic. Natural gas prices are very dynamic. So I just
11 wouldn't want to get into a speculation about what could
12 have happened if things were different.

13 We were -- we were abiding by the Commission
14 orders that had come through and we were at a 40 percent
15 rate.

16 Q. In your testimony you also mentioned that
17 there is a benefit to hedging from stability. I believe
18 you said price stability. Was that correct, sir?

19 A. (Witness Houston) Yes. That's right.

20 Q. Okay. The FCR mechanism recovers whatever
21 fuel costs are actually incurred, whether those costs are
22 high and low through the Part B component; correct?

23 A. (Witness Berrigan) And then it recovers -- I
24 mean, I guess through both components; right?

25 I mean, to the extent that when we set the

1 current FCR, then you're recovering the previously
2 deferred amount. And then we're then tracking and
3 building up a Part A. So, again, it's -- you're
4 recovering it through both components ultimately; right?

5 Q. Yes. But I'm just thinking you're having an
6 FCR hearing.

7 A. (Witness Berrigan) That's right.

8 Q. Part B is the backward-looking one.

9 A. (Witness Berrigan) That's correct.

10 Q. It looks at the --

11 A. (Witness Berrigan) That's right.

12 Q. -- over-recovery/under-recovery section. And
13 it's set to recover based on what that number is. But it
14 sets a certain rate; correct?

15 A. (Witness Berrigan) That's correct.

16 Q. Okay. So the FCR mechanism passes the fuel
17 costs through to customers?

18 A. (Witness Berrigan) Correct.

19 Q. It passes those costs through. For most
20 ratepayers, the fuel costs they pay are stable, regardless
21 of whether the company is hedging or not, because it's
22 determined at the FCR hearing based on the total
23 over-recovery or under-recovery; correct?

24 A. (Witness Berrigan) Yes. Through this -- this
25 proceeding and this process, rates will be set. It'll

1 take into consideration both future -- the expected future
2 costs in the test period, as well as previously incurred
3 costs. And those rates will be set throughout the FCR
4 period.

5 I guess the only change that would occur is
6 to the extent that the over- -- over- or under-recovered
7 balance exceeds the IFR, or interim fuel rider threshold,
8 then the company can come back in -- right? -- make a
9 filing and propose a rate change.

10 And, as a reminder, the company has invoked
11 rate changes four times through the IFR mechanism. Three
12 of those have been rate reductions. And only in FCR-25
13 did we actually have a -- an increase.

14 Q. So isn't that price stability?

15 The fact that we set rates during the FCR and
16 those rates don't change until we change them again?

17 A. (Witness Berrigan) So I think there's maybe a
18 distinction to make between price stability and rate
19 stability; right?

20 I think the hedging program addresses price
21 stability where we're looking to sort of be able to lock
22 in the price of natural gas so that the company knows and
23 we can budget for and set rates based on the price.

24 The IFR mechanism is designed for rate
25 stability; right? So to the extent that prices move,

1 there's over-, under-, recognized balances; right?

2 There's kind of a threshold there for which rates would be
3 unchanged.

4 So, again, there's price stability versus
5 rate stability. And -- and we look at those differently.
6 And, again, the hedging program is meant to try and
7 address the price stability component of that.

8 Q. Understood. I'm just curious about -- for a
9 ratepayer, they pay rates. RTP prices -- RTPs plays
10 prices, but that's not really affected by, as you
11 mentioned, those -- that's just in there -- let me start
12 over.

13 For a regular ratepayer, I feel like they
14 just pay rates. What is the benefit of the company having
15 price stability?

16 A. (Witness Houston) Well, I'm not exactly sure
17 I'm following the question. What flows through the FCR
18 are the costs to procure fuel; right?

19 I mean, that's why we're here today is to ask
20 the Commission, present our case for recovery of fuel
21 prices. The cost of natural gas is a fuel cost. And
22 because that goes through the FCR on dollar-to-dollar, to
23 the extent that you spend a dollar on natural gas, it is
24 going to flow through, ultimately, to the FCR tariff.

25 We're just simply saying to protect the

1 customers from price spikes that could happen at times
2 that we can't predict, we believe the hedge program is --
3 is performing that role.

4 Q. Okay. All right. Let's -- let's move on.

5 I have some questions about the company's
6 position on renewable RFPs and program costs.

7 A. (Witness Berrigan) Okay.

8 Q. In your summary, you mentioned that Georgia
9 Power structures its renewable procurements to collect bid
10 winners' fees and to help defray the cost of the request
11 for proposal process; correct?

12 A. (Witness Houston) Yes.

13 Q. But isn't it true that other costs beyond the
14 cost of performing the RFP process are also included in
15 FCRs, such as company personnel and attorney's fees?

16 A. (Witness Berrigan) Yeah. So the -- the cost
17 related to the -- the renewable programs, and those are
18 the direct costs associated with either managing those
19 programs or negotiating and reviewing contracts that --
20 that are the results of those renewable programs. So,
21 again, think about it as the -- it's the cost to incur
22 those transactions, those contracts. The contracts
23 ultimately provide fuel benefit to customers. And so, you
24 know, the bid fees and winner fees are meant to defray
25 those costs associated with those contracts.

1 Q. Okay. Some of the -- aren't some of the
2 amounts, like the company personnel and attorney's fees,
3 they are -- they run through the FCR, though, rather than
4 base rates; correct?

5 A. (Witness Berrigan) That's correct.

6 Q. Yeah. For the -- yeah. Sorry.

7 A. (Witness Berrigan) And that's how they're --
8 right, that's how they're budgeted. If you look at -- at
9 our -- at our request, we've included the -- those costs.
10 We've also included the projected revenues, or, you know,
11 fees that we would collect from bidders and winners to
12 then, again, offset those costs.

13 And as Mr. Houston said in the opening, the
14 company did identify that we had overstated some of those
15 costs. We filed an errata ultimately adjusting those
16 costs down to where in the -- in the test period, we have
17 projected that costs will more than -- sorry.

18 Revenues will -- will cover more than costs.
19 So it is actually a net decrease in our FCR request.

20 Q. You mentioned that there's been some changes
21 since the company has filed its testimony and those costs
22 that it's seeking to recover. Would you agree that there
23 is currently a gap between the amount that the company is
24 recovering through the fees to cover those RFP programs
25 and the actual costs?

1 A. (Witness Berrigan) For -- and you're specific
2 just to the renewable programs?

3 Q. Yes. The renewable RFP programs.

4 A. (Witness Berrigan) That's right. In the
5 original request, there was a -- a small shortfall.
6 Again, with the errata adjusting the -- the costs related
7 to those programs down, we're now projecting that revenues
8 will more than cover costs.

9 Q. And is that -- does the company anticipate
10 that's the way it will be into the future?

11 A. (Witness Berrigan) I mean, the company -- we
12 would -- again, I think the costs that we're allowed to
13 charge customers I believe are dictated by the Commission.
14 I mean, we would always propose that the costs -- the
15 revenues would more than offset the costs.

16 A. (Witness Houston) Yeah. There are
17 occasionally revenues that we can't budget for. So if a
18 bidder decides that they're going to withdraw their bid or
19 there's some change in the -- the bidding contracting,
20 there may be bid fees that they have to pay. But you
21 can't -- you can't project those; right?

22 And those have happened in the past. So
23 we'll -- we'll take an additional revenue to support this
24 program. So we don't budget that, but there's a --
25 there's a reasonable expectation that that is going to

1 happen, just given how comprehensive these programs are
2 and the -- the number of -- the number of counterparties
3 involved.

4 So I wouldn't say it's 100 percent that the
5 revenues will exceed the costs, but I would say there --
6 there are revenues that we expect to happen that aren't
7 necessarily budgeted because you can't tell exactly when
8 they're going to happen that would flow through here. And
9 the impact of that would be for the benefit of customers.

10 A. (Witness Berrigan) And to be clear, I know
11 I've said "revenue" a few times. Mr. Houston said it.
12 When we talk about revenue, again, we're talking about
13 the -- the income that's brought into the FCR mechanism.

14 This is all, again, contained, as we're
15 proposing it, to stay within FCR. So that when the
16 revenue or the income collected exceeds costs, that it
17 then puts downward pressure on the FCR request.

18 Q. Are you aware that's -- are you aware that
19 staff's recommendation is to move those costs into base
20 rates?

21 A. (Witness Berrigan) If I understand staff's
22 recommendation correctly, they're looking for any amount
23 in excess; right?

24 When the costs are in excess of revenues,
25 those would be deferred into a regulatory asset and dealt

1 with as part of the base rate case.

2 Q. And would not that be consistent with
3 nonrenewable RFPs?

4 A. (Witness Berrigan) Again, I think we're again
5 talking about the RFP; right?

6 These are the RFPs for renewable programs.
7 And, again, our belief is that these renewable RFPs, the
8 renewable contracts that are a result of these, again, are
9 a fuel cost; right?

10 So there's bid fees, winners' fees that are a
11 benefit to fuel costs. There's the cost of administering,
12 you know, the program. There's the cost of administering
13 the RFP, having an independent evaluator.

14 All of those costs, again, we believe are
15 costs -- fuel-related costs. Again, that should be
16 included in the FCR. And so we're just, again, keeping
17 both the revenue or the income with the cost. And, again,
18 believing that that is more appropriate to be part of FCR
19 than it is in base rates.

20 Q. Okay. I want to direct your attention to
21 page 22 of your testimony.

22 A. (Witness Berrigan) Direct testimony?

23 Q. Direct your attention to the direct on
24 page 22.

25 Sorry. Okay. And then on -- on line 12, you

1 stated: The increase in threshold -- this is referring to
2 the -- to IFR mechanism. Sorry. I'm talking about IFR
3 now.

4 Okay. Your testimony states that the
5 increase in threshold will provide a greater rate of
6 stability for customers and allow increased flexibility to
7 absorb natural fuel price fluctuations and normal swings
8 of over -- I'm sorry -- over- or under-recovery balances
9 on a monthly basis.

10 A. (Witness Berrigan) Correct.

11 Q. Okay. So, basically, is this would -- this
12 would give rate stability as well to customers; correct?

13 A. (Witness Berrigan) Yeah. And, again, back --
14 back to my comments earlier, difference between rate
15 stability and price stability. Again, looking at rate
16 stability, we're going to set rates as a part of this --
17 this filing and this proceeding.

18 And that by increasing that IFR threshold,
19 again, that allows for a greater, you know, absorbing of
20 price movements; right?

21 To the extent that -- that prices shift up or
22 down in any given month, there's a little bit more, again,
23 flexibility there for those price movements so that we
24 are -- you know, the company would not have to make a
25 filing and propose rate changes on a more frequent basis.

1 Again, providing stability and rates to customers.

2 Q. I see the importance of having stable fuel
3 rates. But, Mr. Berrigan, would you agree that the
4 objective of the IFR is to ensure that the fuel rates
5 charged are consistent with the fuel balances so that the
6 customers are not significantly over- or under-charged for
7 the cost of fuel?

8 A. (Witness Berrigan) Again, that -- the IFR is
9 a mechanism with a threshold that -- again, if the
10 balances outside are under-recovered -- Part A,
11 under-recovered balances outside, again either above or
12 below, and it has fallen in both directions in the past,
13 that the company then makes a filing and a proposal to the
14 Commission as to what action or inaction should be taken
15 to address rates as it relates to that under-recovered
16 balance.

17 A. (Witness Houston) And I would just add, you
18 know, I think our customers value predictability in their
19 bill; right?

20 When they -- when their bill comes, they like
21 to be able to predict what that -- that dollar amount is.
22 And I think this IFR extending the range adds an element
23 of additional predictability to rate stability and the
24 bills coming through.

25 So we think fewer rate changes is better than

1 more rate changes. That helps our customers, that helps
2 them budget. It's just all around good -- good strategy.

3 Q. But the IFR doesn't itself trigger a rate
4 change; correct, Mr. Houston?

5 A. (Witness Berrigan) The IFR would trigger the
6 requirement to make a filing or a notification to the
7 Commission. And then we would make a proposal as to
8 whether or not we would leave rates where they are or
9 potentially propose a rate change, which then -- anytime
10 the company wants to propose a rate change, it then comes
11 before the Commission and they have to then rule and
12 decide on whether or not that rate change would be put
13 into effect or not.

14 Q. Isn't it true that on at least eight
15 occasions, I think -- I think six occasions in the last
16 year of 2025, the company went outside the \$200 million
17 threshold and, yet, the company never requested a change
18 in FCR rates?

19 A. (Witness Berrigan) That is correct. In 2025
20 calendar year, there were six filings -- six IFR filings
21 made to the Commission. And, to be clear, those -- all
22 six of those were not consecutive.

23 There were several months where we were above
24 the \$200 million threshold and then the balance did go
25 below the \$200 million threshold. And then in December

1 and again went back up above 200 million.

2 So, you know, again, that -- it is a
3 mechanism that requires a notification. It requires the
4 communication of a plan; right?

5 The company's plan in each of those filings
6 was that -- we believe that the -- that the balance
7 exceeding the threshold was a temporary item. And that,
8 you know, there's a lot of factors to consider, that being
9 one of them, and -- when the company made its request to
10 propose no rate change.

11 Q. When the company or -- sorry. When the
12 threshold was exceeded and the company decides not to
13 propose a new rate change, then the -- basically, there is
14 a -- there's an under-recovery and there is a cost to that
15 under-recovery; correct?

16 A. (Witness Berrigan) There -- so, again, you're
17 speaking here, I guess, in more recent terms where we've
18 had the over- -- over-recovered balance. But, yes, there
19 is a -- a cost that's a carrying cost associated with
20 that.

21 And that cost is approved as part of, you
22 know, the -- the mechanism. And we are allowed a -- to
23 recover short-term debt costs because that's how the
24 company finances that; right?

25 So if you think about it, the company has

1 incurred costs above what it budgeted, above what's in
2 rates. And so the company has spent money to pay for
3 those fuel costs, while not passing that increase in cost
4 along to customers; right?

5 So rates -- when rates are unchanged and the
6 balance goes up, then the company is paying for that. And
7 so there is a cost of -- a carrying cost associated with
8 it.

9 But as the Commission has ordered, the first
10 \$15 million of that balance accrues no carrying cost. And
11 then, again, the short-term rate applies. But that's
12 exactly how the company finances that cost.

13 So, again, it's -- think about it as that's
14 the cost of having that balance. And so there's no --
15 there's no benefit to the company of carrying a larger
16 balance and having to finance it. We're just passing
17 along that cost as part of the fuel cost.

18 And it works the other direction, too; right?
19 To the extent that we are over-recovered, we've collected
20 more from customers than what we've spent, we accrue a
21 benefit to customers; right?

22 So they -- they earn interest on the balance
23 and there is no first \$15 million. The first dollar of
24 over-recovery starts to earn a benefit for customers.

25 So, again, it is -- it is symmetrical on both

1 sides using the same rates to determine whether the
2 company is financed or whether the customer is financed.

3 Q. I understand that. And you made that point a
4 couple of times now that the company doesn't make money
5 off of it, is just simply taking the carrying cost it
6 takes --

7 A. (Witness Berrigan) That's right.

8 Q. -- from the under-recovery and passes that
9 through to ratepayers.

10 But it is a cost that is passed to
11 ratepayers; correct?

12 A. (Witness Berrigan) It is part of the fuel
13 cost balance. And, again, that's approved as part of
14 the -- the mechanism.

15 Q. But wouldn't that simply be enough of an
16 incentive or wouldn't the ratepayers be better off if we
17 kept that balance as low as possible, as opposed to
18 expanding the IFR threshold?

19 A. (Witness Berrigan) It's a trade-off; right?

20 I mean, it's a trade-off. You know, it is --
21 are customers better if rates change or are customers
22 better with the stable, predictable rates and that that --
23 again, within a threshold, the balance is then carried by
24 the company as opposed to passing that along through rates
25 again.

1 So it is purely a trade-off. We believe that
2 customers receive a benefit again by having stable,
3 predictable rates without adjusting those on a more
4 frequent basis if costs go -- go up or down.

5 Q. Does the company expect the balance to be any
6 higher or lower in the future?

7 A. (Witness Berrigan) Are you specifically
8 speaking to the Part A balance?

9 Q. I'm talking about -- yes. No. It would be
10 the Part B balance would be the --

11 A. (Witness Berrigan) So, yeah. So the Part B
12 balance -- and, again, what we have proposed in our
13 request is based on -- you know, we had actuals as of the
14 end of the year. There was a projection of where that
15 balance would get -- would get to by May 31, the end of
16 the FCR period.

17 That's how we've always made our filing. And
18 the rates are set based on that amount that was proposed.
19 I believe in our testimony we state that we expected
20 the -- the under-recovered balance to be approximately
21 \$300 million by May 31 of 2026. And that's what we
22 would -- that's what we're designing our three-year
23 recovery to recover.

24 A. (Witness Houston) Yeah. We're not
25 projecting any over- or under-recovery on the forecasted

1 period. We project that revenues to equal costs, no
2 under- -- under- or over-recovery.

3 So, obviously, things can happen in those
4 two-year test periods. So prices can go up and down. As
5 we -- as we say, they create over- and under-recoveries.

6 And just going back to the -- to the hedge
7 discussion we had, that -- that's why the hedge is
8 important, because it helps protect that and help keep it
9 in the range.

10 Q. And, yes, I meant Part A. So thank you for
11 correcting me.

12 MR. COLLADO: I have no further questions
13 currently. I'll reserve the rest of my questions
14 for our rebuttal panel.

15 CHAIRMAN SHAW: All right. Georgia
16 Association of Manufacturers.

17 MR. JONES: Mr. Chairman, I do have questions
18 for the company, but I'm going to reserve them for
19 rebuttal. I think they'll be more appropriate
20 there, given these questions that were just asked.

21 CHAIRMAN SHAW: All right. Georgia
22 Interfaith Power & Light and Southface.

23 MS. WHITFIELD: Good morning, Commissioners.
24 Good morning, panel.

25 MR. HOUSTON: Good morning.

1 MR. BERRIGAN: Good morning.

2 CROSS-EXAMINATION

3 BY MS. WHITFIELD:

4 Q. So the FCR tariff is used by most Georgia
5 Power customers to pay for fuel; correct?

6 A. (Witness Houston) If you're talking about
7 the number of customers, yes, it's residential customers.

8 Q. And the only exception are customers who pay
9 for fuel on the real-time pricing tariff are RTP; correct?

10 A. (Witness Houston) You can be an RTP customer
11 and there's a baseline charge there, which does include
12 FCR, yes.

13 Q. Although, new data centers aren't expected to
14 have that baseline charge; correct?

15 They're expected to pay for 100 percent of
16 their energy on RTP?

17 A. (Witness Houston) Well, that -- that's a
18 good point. And Matt and I -- Mr. Berrigan and I, we're
19 not pricing experts. So we can't talk to the -- the
20 components of the tariffs there.

21 Q. But are you aware that that's the case for
22 new data centers; that they will be pricing 100 percent of
23 their energy on RTP?

24 A. (Witness Houston) I'm aware that there's a
25 rate and I'm aware that there's no CBL component to that.

1 But other than that -- and also knowing that RTP is a
2 large component of that. Other than that, I can't really
3 speak to the way those tariffs are constructed.

4 Q. Okay. FCR tariff is priced per
5 megawatt-hour; correct?

6 A. (Witness Houston) It's in a kilowatt-hour,
7 yes.

8 Q. Okay. So if a customer on the FCR tariff
9 uses more energy, they will pay more money; correct?

10 A. (Witness Houston) Correct. Yes.

11 Q. And the total fuel cost to Georgia Power are,
12 likewise, driven by two things: One, the price of fuel,
13 and the second being the amount of fuel sold; correct?

14 A. (Witness Houston) Yes. The cost to procure
15 fuel and the amount sold, yes.

16 Q. So first I want to talk about the historical
17 period in which Georgia Power is asserting that it didn't
18 collect enough money to cover its cost; correct?

19 A. (Witness Houston) Correct, yes. We ended up
20 with an under-recovery, yes.

21 Q. During the historical period, at the time of
22 your direct testimony, total fuel costs were about
23 2 percent higher than you expected during the last FCR
24 docket, which means that they were about \$185 million more
25 than you had projected in 2023; correct?

1 That's page 9, line 18, if you want to take a
2 look.

3 A. (Witness Houston) Correct, yes.

4 Q. And this is not because of price, but,
5 instead, the increase in cost was driven by the fact that
6 Georgia Power burned more fuel; right?

7 A. (Witness Houston) Yeah. I mean, the --
8 the -- what led to the under-recovery in the historic
9 period was a combination of, yes, burning more coal
10 generation and having a lower expectation of RTP revenue.
11 Those were the two main drivers.

12 Q. Sure. And the burning more coal was what
13 drove up costs, having less RTP revenue is what brought
14 revenue down. So when combined, you had an
15 under-recovered balance; correct?

16 A. (Witness Houston) Yeah. There were other
17 factors. There were -- natural gas prices was actually a
18 positive to offset that. So there are a number of
19 different factors, but those would be the two largest
20 factors I think contributing to the under-recovery.

21 Q. Sure. So I'm glad you mentioned that. Costs
22 in total went up. But as you just mentioned, gas prices
23 during the historic period for the company were 23 percent
24 lower than you had budgeted in 2023; correct?

25 A. (Witness Houston) Yes. That's correct.

1 Q. And coal prices were 36 percent lower than
2 you budgeted in 2023; correct?

3 A. (Witness Houston) Yes.

4 Those are both on Page 10; correct?

5 Q. Correct, yes.

6 But for everyone paying the FCR tariff,
7 which, as you mentioned, is residential customers, small
8 businesses, they paid a rate based on the higher budgeted
9 price for coal and gas for the last three years; correct?

10 A. (Witness Houston) Well, these -- these
11 increases in price were not in their rate going over the
12 last three years. What the customers paid was the FCR
13 rate that was approved in FCR-26.

14 Q. Right.

15 A. (Witness Houston) And not -- these costs are
16 included in this current rate request, but did not impact
17 the bill over the last three years.

18 Q. Correct. So in the historic period, coal
19 prices were 36 percent lower than you projected and that
20 you incorporated in the FCR-26 rate. And gas prices were
21 23 percent lower than you projected and had incorporated
22 in the FCR-26 rate; correct?

23 A. (Witness Houston) Yes. Correct.

24 Q. So customers paying the FCR-26 rate were
25 paying for those higher prices of coal and gas, as you had

1 projected in 2023; correct?

2 A. (Witness Houston) Yes. That's correct.

3 Q. But you're not proposing a refund for those
4 customers based on paying more than the cost during the
5 historic period, are you?

6 A. (Witness Houston) No, we're not. And this
7 is how the FCR tariff works. Customers only pay for the
8 cost that the company incurs on a dollar-for-dollar basis.

9 So to the extent costs change over time,
10 which as your questions evidence, they do change over
11 time, we fully expect that sometimes costs are going to be
12 above, sometimes costs are going to be below. But
13 ultimately what the customer pays over FCR periods is the
14 actual cost we incur.

15 So it's incumbent on us to manage those fuel
16 costs and that's where our focus is. We cannot predict
17 market volatility, market prices. And, as you know,
18 things happen in the macro environment and happen
19 internationally that -- that impact these things.

20 So to the extent that prices change, that
21 should not be a surprise. And in this case we're just
22 asking for recovery of the actual fuel costs we incurred.
23 Nothing more, nothing less.

24 Q. Sure. And you -- we just covered that the
25 increase in total cost to the company was driven by

1 increased generation by burning more fuel; correct?

2 A. (Witness Houston) Yes. That's right.

3 Q. But your accounting that leads to the
4 under-recovery says that the revenue has not kept up with
5 that increased generation; correct?

6 A. (Witness Houston) Yes.

7 Q. And revenue didn't fall short because
8 customers on the FCR tariff didn't pay their bills; right?

9 I mean, that wasn't the shortfall?

10 A. (Witness Houston) Not that I'm aware of, no.

11 Q. Customers on the FCR fuel tariff were paying
12 a rate that accounted for the higher price that was
13 actually incurred we just covered. But you testify that
14 there is a revenue shortfall because less money was
15 collected from RTP customers, the larger customers, than
16 was expected in the last fuel budget; correct?

17 A. (Witness Houston) Yeah. I mean, I think, as
18 we stated before, under-recovered balance was \$300 million
19 approximately. I think that's the forecast of the
20 under-recovered balance at the end of May.

21 One of the contributing factors was how we
22 budgeted for RTP revenue. And that was approximately
23 \$300 million. So if you -- that really explains a lot of
24 the -- like, the under-recovered balance.

25 Q. Yeah.

1 A. (Witness Houston) And -- and I would say
2 that that was in FCR-26 where, you know, we already had
3 significant -- we were looking at significant increases
4 because of the war in Ukraine, Russia where -- our initial
5 filing was an increase of \$23. And as we got closer to
6 the hearing and closer to rates changing, we really wanted
7 to focus on: Are there ways to get that request down?

8 So we updated the natural gas prices.
9 Ultimately, we ended up taking \$7 off that. So that was
10 sort of the genesis of -- of bringing rates down.

11 And one thing we didn't actually update in
12 FCR-26 was the expectation of RTP revenues. If we had
13 updated that, that 7, \$8 that we talked about, the benefit
14 and the decrease, that would have been somewhat less.

15 We just -- at that time we thought there's a
16 number of different assumptions. We are not going to
17 change that. If we change it, then customers will end up
18 paying more in FCR-26. So it was a decision that we made
19 at the time.

20 Q. Are you testifying that you didn't adequately
21 account for the costs that RTP customers would pay at the
22 time of the last fuel docket?

23 A. (Witness Houston) No. I'm saying there are
24 a number of different assumptions and things that can be
25 updated and otherwise. This was one -- one that we did

1 not update.

2 Just the same way as -- say, if natural gas
3 prices increased in this current period, we may not
4 propose an increase to what we originally filed. So it
5 was just an assumption of a subjective element.

6 Q. So in light of Georgia Power's choice not to
7 update the RTP revenue prices in the last fuel docket, is
8 Georgia Power proposing to waive all the carrying costs
9 that were incurred for the revenue shortfalls during
10 the -- during the intervening time?

11 A. (Witness Houston) No. Like I said, there's
12 a number of things that go into the over/under recovery,
13 whether it's RTP, coal prices, natural gas prices. It's
14 just a number of things. So we don't want to -- we would
15 not be picking out individual components and doing as you
16 suggest.

17 Q. And you mentioned that the revenue shortfall
18 is about 300 million. Your testimony, to clarify, says it
19 was \$324 million or fell short of projected RTP revenues
20 by about 23 percent; correct?

21 A. (Witness Houston) That's correct.

22 Q. So moving to the forward-looking period,
23 Georgia Power is projecting that its sale of energy using
24 RTP will grow from making up roughly a quarter of all
25 energy sold by Georgia Power's retail customers, to making

1 up roughly half of all of Georgia Power's retail energy
2 sales by the summer of 2029; correct?

3 A. (Witness Houston) Can you point me to where
4 that is?

5 MS. WHITFIELD: Sure. May Mr. Sherrier
6 approach, Commissioner?

7 CHAIRMAN SHAW: Yes.

8 MS. WHITFIELD: Thank you.

9 BY MS. WHITFIELD:

10 Q. I'm handing you MFRP 1, which is a retail
11 megawatt-hour sales tab. And it has been -- has it been
12 marked?

13 Did you mark that one?

14 MR. SHERRIER: No.

15 MS. WHITFIELD: What's the next number? 16.

16 We'll mark that one as GIPL Exhibit 16.

17 Sorry. GIPL/Southface Exhibit 16.

18 (The document referred to was marked for
19 identification as GIPL/SOUTHFACE Exhibit 16.)

20 BY MS. WHITFIELD:

21 Q. So on this tab you can see the non-RTP
22 projected sales versus the total retail projected sales,
23 which includes RTP. And rough math reflects that
24 currently projected sales are about a quarter of Georgia
25 Power sales and they will go up to about half of Georgia

1 Power sales by summer 2029; right?

2 A. (Witness Houston) Sorry. There's -- there's
3 a lot of numbers on here. I'm just not following.

4 Q. Take your time.

5 A. (Witness Houston) Can you please repeat the
6 question?

7 Q. Sure. Georgia Power is projecting that its
8 sale of energy to RTP customers will grow from making up a
9 quarter of all of its retail sales to about half of its
10 retail sales by summer 2029.

11 A. (Witness Houston) So I don't see any
12 percentages on the schedule.

13 Q. No. It requires a little math.

14 A. (Witness Houston) Okay.

15 Q. But I -- I suppose we could do it this way.
16 Would you agree that if you take the non-RTP sales and you
17 compare that to the total FCR applicable sales, which
18 includes both RTP and non-RTP, you could come up with a
19 percentage based on these numbers?

20 A. (Witness Houston) Would it be helpful to use
21 the line numbers?

22 Q. Sure. So the non-RTP sales aren't numbered.
23 They're at the very bottom. And the total FCR applicable
24 numbers are listed there on a monthly basis.

25 A. (Witness Houston) Total territorial supply?

1 Q. And at the top you have total FCR applicable
2 sales.

3 A. (Witness Houston) Okay.

4 A. (Witness Berrigan) Yeah. I mean, if you're
5 comparing those two numbers, the -- the percentage is
6 increasing.

7 Q. All right. Subject to my -- the check of my
8 math based on this exhibit, would you agree that this
9 exhibit reflects the total amount of non-RTP sales as
10 compared to the total sales, which includes non-RTP and
11 RTP?

12 A. (Witness Houston) Yeah. Okay. So if you're
13 saying total territorial supply by month, that's -- that's
14 growing over the number of months that you state does
15 actually go beyond our test period --

16 Q. Yes, they do.

17 A. (Witness Houston) So that's not applicable
18 to this case. And then the bottom line is the non-RTP.
19 Yes, I agree that as a percentage, non-RTP has a lower
20 percentage of the total territorial supply.

21 Q. Okay. And then, on average, during the
22 two-year test period, would you agree that RTP energy
23 sales are expected to account for over 30 percent of
24 Georgia Power's energy sales?

25 A. (Witness Houston) Yes. If you -- well, if

1 you had the commercial class and the industrial class
2 together, which I think would be -- have a substantial RTP
3 component for some of those totals, about 7 million
4 megawatt-hours here, with a total territorial --
5 territorial supply of about 10.6.

6 Q. And I'm actually doing something a little bit
7 different, recognizing, as you mentioned earlier, that
8 some of the commercial and industrial historical customers
9 have some sales on RTP and some on non-RTP.

10 A. (Witness Houston) Yes.

11 Q. And so I was arriving at 30 percent by
12 comparing that non-RTP megawatt-hour number at the bottom
13 to the billed total sales at the top, which includes
14 non-RTP and RTP.

15 A. (Witness Houston) Okay. Yes.

16 Q. Okay. So I want to dive into RTP revenue and
17 how it comes into play in the fuel docket.

18 A. (Witness Houston) Okay.

19 MS. WHITFIELD: May Mr. Sherrier approach?

20 CHAIRMAN SHAW: Yes.

21 MS. WHITFIELD: And, Bob, if you could hand
22 out the next, like, four; 6.5 Exhibit 1 summary
23 just for --

24 (The document referred to was marked for
25 identification as GIPL/SOUTHFACE Exhibit 1.)

1 BY MS. WHITFIELD:

2 Q. So Mr. Sherrier will be handing you an
3 exhibit that has been marked as GIPL/Southface Exhibit 1.
4 And it is labeled MFRP 6.5. And this is the public
5 disclosure version of this exhibit.

6 And it's an exhibit that at the top says:
7 Variable Fuel Cost Components. And it lists the various
8 components that are included in the FCR docket, the FCR
9 account. And I'll let you take a look at that when you
10 get it.

11 He is also handing you MFRP 1, Exhibit 1.
12 That is not GIPL/Southface Exhibit 1, but rather Exhibit 1
13 of Georgia Power Company. That is the label of the tab in
14 that particular exhibit.

15 And in that exhibit, most -- well, all of the
16 monthly columns have been hidden so that you just see the
17 total fuel cost column. But it is, otherwise, identical
18 as provided on the docket.

19 And when you've had a chance to familiarize
20 yourself with MFRP 6.5, if you could let me know, that
21 would be great.

22 MS. WHITFIELD: And for the purposes of
23 identification and for the court reporter, we will
24 label MFRP Exhibit 1, GIPL/Southface Exhibit 17.

25 Oh, it's labeled. It's labeled 14. I'm

1 sorry.

2 (The documents referred to was marked for
3 identification as GIPL/SOUTHFACE Exhibit 14.)

4 BY MS. WHITFIELD:

5 Q. Have you had a chance to take a look at
6 MFRP 6.5?

7 VICE CHAIRMAN MCDONALD: Are these -- are
8 these prices that you're talking about, the fuel
9 costs, does this include the price of those that
10 are shared with other utilities?

11 MS. WHITFIELD: Do you want to ask them that
12 or me?

13 VICE CHAIRMAN MCDONALD: I'm looking at your
14 handout.

15 MS. WHITFIELD: This is -- are you looking at
16 Exhibit -- MFRP Exhibit 1, GIPL/Southface 14?

17 VICE CHAIRMAN MCDONALD: Correct.

18 MS. WHITFIELD: Yeah. This is the --

19 VICE CHAIRMAN MCDONALD: For Plant Scherer.

20 MS. WHITFIELD: This is the total fuel
21 expenses charged in the fuel account under FCR-27
22 to retail customers.

23 VICE CHAIRMAN MCDONALD: So that's the fuel
24 for Georgia Power; is that correct?

25 MS. WHITFIELD: Correct. Charged to our

1 retail customers, yes.

2 VICE CHAIRMAN MCDONALD: How is that broken
3 up?

4 MR. BERRIGAN: I'm sorry, Commissioner?

5 VICE CHAIRMAN MCDONALD: When you've got,
6 like, Plant Scherer shared by Oglethorpe and
7 Georgia Power --

8 MR. BERRIGAN: Yes, sir.

9 VICE CHAIRMAN MCDONALD: -- how is that
10 broken out?

11 MR. HOUSTON: So we -- we do joint owner
12 accounting. So we will incur the costs and then we
13 will bill the joint owners for those costs. And
14 that's done on a monthly basis.

15 Those costs are not in our fuel cost recovery
16 at all. Those are taken out.

17 VICE CHAIRMAN MCDONALD: Are you talking
18 about these?

19 MR. HOUSTON: Yeah. So to the extent that we
20 have co-owners in the joint plants, those costs are
21 not in our request at all, yes.

22 MR. BERRIGAN: The costs included here are
23 Georgia Power's proportionate share of those costs.

24 VICE CHAIRMAN MCDONALD: Okay.

25 MS. WHITFIELD: Are you ready?

1 MR. HOUSTON: Yes.

2 BY MS. WHITFIELD:

3 Q. Okay. So taking a look at the exhibit that
4 is labeled MFRP 6.5, you agree that this describes various
5 buckets of the -- of the fuel cost components in the FCR
6 account for retail customers; correct?

7 A. (Witness Houston) Yeah. It gives a total
8 fuel cost for the test period, which is comprised of
9 elements around, you know, molecules of the actual fuel.
10 So coal, natural gas. Taxes obviously gets included.
11 Emission allowances, as appropriate, and then other
12 components just on, you know, running the coal. So that's
13 what this describes.

14 Q. And I'd like to draw your attention to Letter
15 "N" under: All other cost components. And Item "N"
16 reflects that RTP fuel revenues are included as a cost
17 component here; correct?

18 A. (Witness Houston) Yes. But this was
19 referring to the RTP fuel credit. So RTP customers
20 contribute to the fuel recovery, FCR, by taking a portion
21 of their bill and applying that credit to the FCR balance.

22 Q. And if you look at what has been labeled in
23 handwriting as MFRP Exhibit 1, this Exhibit 1, this
24 exhibit, likewise, provides the value for many of the LIDA
25 items in the retail fuel account, including the RTP fuel

1 revenues that are credited to the FCR account; correct?

2 A. (Witness Houston) Yes, that is correct. So
3 this schedule shows projected fuel expenses for the test
4 period and then RTP fuel credit -- credit of \$1.5 million
5 against those costs.

6 Q. And that is a -- that's on Line 46 where you
7 see that; correct?

8 A. (Witness Houston) Correct.

9 Q. And do you agree that the RTP fuel credit is
10 offsetting approximately 20 percent of the total fuel
11 costs in this accounting?

12 A. (Witness Houston) Yes. The -- the math
13 would be approximately 1.5 million divided by 6.8. So
14 that's somewhere close to 20 percent.

15 Q. Okay. So you just used the term "RTP fuel
16 credit." I will also use the term "RTP fuel credit" to
17 refer to line 46 that we just described, or Number "N" on
18 MFRP 6.5; okay? Because there's a lot of terminology in
19 this -- in this space. I just want to make sure we agree.

20 So the fuel tariffs for smaller customers who
21 are paying the FCR tariff, those are calculated
22 differently than the fuel tariffs for larger customers on
23 RTP or the fuel credit for larger customers on RTP;
24 correct?

25 A. (Witness Houston) Yes. There's a -- there's

1 a -- the RTP fuel credit methodology, which has been
2 approved by this Commission, and I think has -- was last
3 reviewed in 2010 and has gone through the discovery
4 process and approvals.

5 There is an approved methodology for how
6 that's calculated. That is run through -- my team does
7 not administer that. And I'll just have you know that on
8 the rebuttal test -- on the rebuttal panel, we do have
9 Mr. Evans that can talk about the RTP fuel credit
10 methodology.

11 So if you have questions around that, I would
12 just reserve those for him, if possible. But I would
13 agree that there's a fuel credit methodology, which is
14 different from the way the FCR rate is calculated.

15 Q. Okay. I'm going to go ahead and ask you
16 because you testified about, you know, the -- the fuel
17 docket generally, 20 percent of it is paid for by RTP.
18 And the data request here, STF-JKA-1-4 supplemental, which
19 has been marked as GIPL/Southface Exhibit 2, if you turn
20 to the second page of that data request, that describes
21 the difference between the formula for the RTP fuel credit
22 and the components of the RTP price; correct?

23 A. (Witness Houston) Yes. That is correct.

24 (The document referred to was marked for
25 identification as GIPL/SOUTHFACE Exhibit 2.)

1 BY MS. WHITFIELD:

2 Q. And are you able to speak to those
3 differences and how those differences -- the fact that
4 there is a difference?

5 Are you familiar with this?

6 A. (Witness Houston) Yeah. I mean, for the --
7 the RTP, they had hourly prices. That's based on
8 projections of hourly running costs and incremental
9 generation. And then the amount of the fuel charge for
10 the FCR is based on the hourly average marginal fuel cost.

11 So I do acknowledge that there are
12 differences there. As it relates to how RTP -- RTP is
13 priced today here and in our head and how the demand
14 response works on that, I would direct you to Mr. Evans.

15 Q. Sure. So I -- I want to acknowledge one
16 thing for us, which is there's underlining on this
17 document -- this data request response that is not Georgia
18 Power's. That is mine just to help you look at the -- the
19 things that I'm asking you questions about.

20 But when it comes to price, as you mentioned,
21 there's the -- the piece that's generally considered the
22 fuel component, which is lambda. And you described that
23 as the hourly running cost of incremental generation as
24 reflected in this document.

25 But then there's also provisions for losses,

1 which are incorporated into lambda. There's projections
2 of hourly transmission costs. There's reliability
3 capacity costs. And then there's a 2 to 3 mil per
4 kilowatt-hour recovery factor, depending on a day ahead or
5 hour ahead; correct?

6 A. (Witness Houston) Yes. That's correct.

7 Q. And are you aware that the revenue from the
8 last three categories -- transmission, reliability and the
9 recovery factor -- are used entirely to offset base rates?

10 Those revenues do not show up in the fuel
11 costs docket?

12 A. (Witness Houston) Yeah. I'm generally aware
13 of this, but I, again, would direct you to Mr. Evans,
14 pricing and rates director, who can give you the exact
15 answers on that.

16 MS. WHITFIELD: Okay. Sorry, Commissioners.

17 I'm going to take a minute to make sure that -- I
18 expected this panel to be able to speak to RTP. So
19 I need a minute to rejigger and make sure that I'm
20 asking them only what is in their wheelhouse.

21 BY MS. WHITFIELD:

22 Q. All right. Let's turn to firm
23 transportation.

24 A. (Witness Houston) Yep.

25 Q. 100 percent of the costs of reserving gas

1 pipeline space called firm transportation are added to the
2 fuel cost recovery accounts to be paid for as determined
3 in this docket; correct?

4 A. (Witness Houston) Yes. That is --
5 generally, that is correct. But I will point your
6 attention to Page 19, where we do have some costs for
7 units that are outside the test period where our
8 commitment is to sell that capacity. If we sell more --
9 if we sell at a higher price than what it's costing us,
10 that benefit will flow back to customers.

11 So, yes, generally, you're correct. But
12 there is one example where we have removed those costs
13 from this FCR.

14 Q. When you say you've removed those costs, I
15 see on the projections of costs that you are projecting to
16 be able to resell that firm transportation. By testifying
17 here today that you have removed those costs, does that
18 mean that you are testifying that if you don't resell that
19 volume of firm transportation, you won't count that as an
20 under-recovery in a future docket?

21 A. (Witness Houston) Yeah. What I mean by
22 remove is that there -- if there's a line item in the
23 request of a dollar amount, but it's equal and offsetting
24 amount to remove it from the request. So it's not
25 reflected in this -- these rates that we're talking about

1 today, we will go ahead and market that capacity. If we
2 end up with a higher -- higher price than what we paid for
3 it, that flows back through the FCR. And the opposite is
4 also true. That will flow through back to the FCR.

5 Q. So let's talk about the total cost for firm
6 transportation. You mentioned the firm transportation for
7 future generation. That is the bucket of costs that
8 you're referring to.

9 MS. WHITFIELD: Bob, could you hand out the
10 firm transportation MFRP 1 tab.

11 May Mr. Sherrier approach?

12 CHAIRMAN SHAW: Sure.

13 BY MS. WHITFIELD:

14 Q. So I'll refer you to, first, MFRP Exhibit 1,
15 which is already in front of you, lines 40 and 41. On
16 those lines, you have firm transportation for future
17 generation. You have a cost for that total. And then you
18 have the cost backed out based on the projected sale
19 proceeds.

20 And that's firm transportation for Bowen and
21 Wansley; correct?

22 A. (Witness Houston) Yeah. So this is related
23 to the construction of the Bowen and Wansley CC units that
24 were approved by this Commission in the certification and
25 supplemental request, which really is just a reflection of

1 the growth in Georgia and meeting this demand.

2 And as we talked about very much earlier on,
3 this increased load is really allowing us to have a
4 minimum amount of revenues, like lock in a minimum amount
5 of revenues for the 2028 rate case, which is giving
6 customers a benefit of \$1.6 billion.

7 So I just wanted to draw out the arc of where
8 this is coming from and the benefits customers will see
9 from these units, you know, that serve this load. And
10 there's the downward pressure that all of this taken
11 collectively will put on customers' rates.

12 Q. So you mentioned downward pressure. But if
13 you take a look at the exhibit that was just handed out,
14 this is, again, an exhibit -- this is -- at the top of
15 this exhibit, it's labeled MFRP 1. It's the firm
16 transportation tab of MFRP 1. And it's been labeled
17 GIPL/Southface Exhibit 15.

18 The handwriting on this tab on this document
19 is mine, not Georgia Power's. And here I've provided you
20 with some math assistance since it's a lot of math to do
21 in your head.

22 (The document referred to was marked for
23 identification as GIPL/Southface Exhibit 15.)

24 BY MS. WHITFIELD:

25 Q. But would you agree that this new firm

1 transportation cost that you're referring to amounts to
2 several hundred million dollars a year?

3 A. (Witness Berrigan) Yeah. I think what's
4 helpful to recognize -- you touched on it earlier and it's
5 true. All firm transportation costs -- right? --
6 transportation costs related to any fuel source are
7 recovered through the FCR; right?

8 So this is no different than any other FT
9 that the company is able to lock in for any of it -- it's
10 transportation costs for any of its units; right?

11 This specific FT that we're talking about
12 here is related to new construction. As Mr. Houston said,
13 those units were approved through the certification
14 request; right?

15 Firm transportation costs were part of the
16 cost that was contemplated. Again, so we're talking about
17 a cost that's already been contemplated, the recovery of
18 which has always gone through fuel.

19 And, yes, there is a point that these new
20 costs are -- that start that is ahead of when those units
21 are available. That's because this is related to a newly
22 constructed pipeline. And that's to be able to have
23 access to this firm transportation to run the units that
24 were certified for use to benefit customers. This is
25 the -- the contract that the company -- the company

1 signed.

2 And as Mr. Houston said, you know, we have
3 plans -- right? -- understanding that those units will not
4 be online in this test period. The company has plans on
5 how it can mitigate the cost of this FT; right? That
6 includes selling it; right?

7 There's -- and there's a couple of different
8 options the company has to try and sell those costs. But,
9 again, it's a mitigation plan to try and offset the cost
10 of something that's already been included, approved, and
11 is historically included in this recovery mechanism.

12 A. (Witness Houston) I mean, if you -- if
13 you're just pointing out that firm transportation costs
14 are going up, yes, that is true. That is an order to
15 build these units to serve new load, growing Georgia,
16 industry coming to the state, gives us the opportunity to
17 have a rate freeze and other things.

18 And also in the 2028 rate case to put
19 downward pressure on rates by locking in revenues. So
20 there's a -- there's a whole bunch of benefits that come
21 from costs. Cost will end up with more revenues down the
22 line.

23 Q. So you didn't answer my question, though,
24 which is: Do you agree that the new firm transportation
25 costs amount to a couple hundred million dollars a year?

1 A. (Witness Houston) If I say your handwriting
2 math here?

3 Q. Subject to checking my handwritten math;
4 correct?

5 A. (Witness Houston) Yes. This is not on a
6 calendar year. This is on a 12-month period, so...

7 Q. 12-month period; correct?

8 A. (Witness Houston) Yep. That's correct.

9 Q. And a little over 75 million of that is due
10 to Plant Yates specifically; correct?

11 A. (Witness Houston) Yes. That looks like the
12 math.

13 Q. And when you talk about resale, you're
14 talking about -- not Plant Yates. You're talking about
15 the firm transportation that's been attributed to Bowen
16 and Wansley; correct?

17 A. (Witness Berrigan) That's right. The cost
18 associated with Plant Yates is to provide additional
19 benefits specific to those units at Plant Yates; right?

20 That allows those units in the winter months
21 to run on gas, which is more efficient than running on
22 oil. And so there is an actual benefit that would be
23 derived from having firm transportation at those units
24 that maybe otherwise would not have been available in this
25 period.

1 Q. Georgia Power believes that if everyone
2 benefits from a grid asset, like firm transportation, it
3 means everyone should pay for that grid asset; correct?

4 A. (Witness Houston) If it's a cost of fuel,
5 yes, that is correct.

6 Q. Do you agree that residential and small
7 business customers should not have to pay for a data
8 center's share of firm transportation costs?

9 A. (Witness Houston) If -- I don't think
10 there's any subsidization. I think residential customers
11 are seeing great benefits coming out of this growth of
12 Georgia, this large load. Like I talked about the rate
13 freeze, the downward pressure.

14 So there are great benefits out of large
15 load. You know, for a long time we have not had load
16 growth and now we have it. And it gives us a real
17 advantage to drop the rates for everyone, and especially
18 residential customers.

19 Q. To be clear, when you describe the great
20 benefits, you're talking about the benefits that Georgia
21 projects -- Georgia Power projects that we will see in the
22 next rate case and the benefits that has led to the rate
23 agreement or the rate settlement last fall.

24 You're not, though, talking about benefits in
25 this fuel docket that we're having right now, are you?

1 A. (Witness Berrigan) We operate our units as a
2 system; right?

3 We don't assign any unit to any specific
4 customer, type of customer, class of customer; right?

5 So, again, we're operating all of our units
6 as a system. The costs of all of our units as a system,
7 the fuel costs, are, again, included here for recovery.
8 There are recovery mechanisms; right?

9 We've talked about FCR, that recovery
10 mechanism. We've also talked a little bit about the --
11 the RTP fuel credit where RTP customers are paying their
12 share of costs based on the methodology that was
13 previously approved through the 2010 base rate case and
14 subsequently through fuel cases.

15 And so, again, it's an allocation of costs
16 to -- based on tariffs, not based on individual customers,
17 individual -- you know, again current or future customers.
18 And so, yes, all customers are benefiting by having more
19 efficient units on the system; right?

20 Each time we add a unit here or we add a
21 solar facility or we add any type -- right? -- that's part
22 of the benefit of having our diverse generation mix is
23 that we have several different types of units that we can
24 run. And, again, all customers are benefiting from that,
25 so...

1 VICE-CHAIRMAN MCDONALD: Going back to the
2 original question, though --

3 MR. BERRIGAN: Yes, sir.

4 VICE CHAIRMAN MCDONALD: Does the residential
5 ratepayer paying into the transportation costs of
6 the fuel that goes into databases?

7 That was -- was that the original question?

8 MS. WHITFIELD: That's right.

9 BY MS. WHITFIELD:

10 Q. Does Georgia Power believe that residential
11 and small business customers should be subsidizing the
12 firm transportation gas costs for data centers?

13 A. (Witness Berrigan) I am not -- I wouldn't
14 characterize it as subsidizing costs. Again, it's a cost
15 to run assets to provide benefit to residential customers;
16 right?

17 These are assets that residential customers
18 will also have the ability to use. Again, it's based on a
19 dispatch model that determines each unit that runs at each
20 point throughout the day. But all customers benefit from
21 all those units.

22 And, again, firm transportation is a fuel
23 cost. It's the transportation cost for natural gas units.
24 And so, yes, it's appropriate to include FT costs in the
25 FCR costs that we're seeking recovery of.

1 Q. I agree.

2 Would you be surprised to learn -- since
3 you're not RTP experts, would it surprise you to learn
4 that RTP customers are contributing zero dollars to firm
5 transportation costs in the fuel docket?

6 A. (Witness Houston) I don't think that's true.
7 I mean, we've got the RTP fuel credit, which is
8 calculated. That is a separate methodology. There are a
9 number of components that go into it.

10 Sure, the marginal cost of fuel is one thing
11 but there are other elements that you rightly pointed out.
12 And so the construct of how that's been put together and
13 the methodology and how RTP is being billed has gone
14 through this Commission process, has been reviewed. We
15 are not proposing any changes to tariffs -- right? -- in
16 this proceeding.

17 So it is complicated. There are a number of
18 elements go into how RTP is billed, how the RTP fuel
19 credit methodology is defined, which actually has been
20 approved by this Commission. And I would just say for
21 the -- for the finer points of the question there, I would
22 ask that you ask those questions of the next panel.

23 Q. I also didn't think it was true before this
24 docket, but I will have the next panel explain why it is.

25 Okay. Renewable program expenses. You

1 discussed this with staff and you -- I believe I heard you
2 testify already that you agree that RTP customers benefit.

3 You testified that all customer benefit from
4 our renewable programs; correct?

5 A. (Witness Berrigan) Correct.

6 Q. Which would, of course, include RTP
7 customers; correct?

8 A. (Witness Berrigan) Correct. It's part of our
9 customers.

10 Q. And 100 percent of the expenses for the
11 renewable programs are included in the fuel cost recovery
12 accounting; correct?

13 A. (Witness Berrigan) Expenses, as well as
14 revenues, yes.

15 Q. Correct.

16 Would it surprise you to learn that non-RTP
17 customers pay 100 percent of these costs as part of their
18 fuel charge?

19 A. (Witness Berrigan) Are you asking again
20 related to the RTP credit methodology and how that works?

21 And, again, that -- again, Mr. Houston and I
22 are not experts on the fuel credit methodology. That's
23 Mr. Evans.

24 Q. Okay. I'd like you to take a look at MFRH-2,
25 which is trade secret.

1 MS. WHITFIELD: If Mr. Sherrier may approach.
2 It was the first one, I believe.

3 BY MS. WHITFIELD:

4 Q. You mentioned in response to staff's
5 questions that you filed an errata that reflects that your
6 revenue will more than cover your costs.

7 But if you look at MFRH 2, it shows that
8 that's what you thought during the last fuel cost, as
9 well. You projected the same thing. That your revenue
10 would cover your costs.

11 But, in fact, towards the bottom of that
12 exhibit, you will see that in the historic period there's
13 a shortfall, leaving -- of \$5 million; correct?

14 It's towards the very bottom, the row: Net
15 Renewable Program Expenses, where you're comparing the
16 FCR-26 budget to actual expenses.

17 A. (Witness Berrigan) Okay.

18 Q. And you can see that during the FCR budget
19 you are projecting revenue as a result of this program and
20 these -- this cost bucket. But, in actuality, it led to
21 significant expenses; correct?

22 A. (Witness Berrigan) Again, without using the
23 numbers. You know, this, again, is for the period of
24 January of '23 and December of '25.

25 Q. Correct.

1 A. (Witness Berrigan) So this is not on an
2 FCR-26 basis.

3 Q. It's the historic period.

4 A. (Witness Berrigan) It's the historic period,
5 that's correct; right?

6 Which, again, doesn't necessarily align with
7 the FCR period. And so, yes, this is a point in time
8 showing the projection versus the actual. And there is a
9 difference.

10 Q. Okay. And by difference, you recognize that
11 the difference is a net cost to customers that will be
12 paid for?

13 A. (Witness Berrigan) In this three-year
14 period. Again, you're taking five months out of FCR-25
15 and you're -- or six months -- seven months out of FCR-25,
16 and you're excluding five months out of FCR-26 in this
17 analysis, if you're just doing the math; right?

18 Q. It's your analysis.

19 A. (Witness Berrigan) You're -- well, again,
20 we're comparing numbers that are not based on an FCR
21 period; right?

22 So, again, what we've stated is that on an
23 FCR basis we believe that costs will be offset by
24 revenues. This is a point in time; right?

25 A three-year period that doesn't align with

1 FCR periods. So, again, to assess from an FCR
2 perspective, we would need to go look at the actual FCR
3 period. Over this specific period of time, yes, what we
4 expected and what happened were different and that
5 resulted in more costs.

6 Q. Are you suggesting that the company has made
7 up for that balance in the last six months of the FCR
8 period?

9 A. (Witness Berrigan) I don't have -- I guess
10 I'm -- again, I'm looking at information as of a
11 three-year period, not based on an FCR period. All I'm
12 saying is that -- again, to make an assessment against FCR
13 periods, we would need to have a different series of data
14 points.

15 Q. Is that a series of data points that you
16 could provide as a supplement to MFRH 2 that Georgia Power
17 provided in the docket?

18 A. (Witness Berrigan) For the FCR-26 period is
19 still ongoing.

20 Q. So it's -- your critique is that there's
21 still ongoing costs that aren't reflected here?

22 A. (Witness Berrigan) I'm -- all I'm doing is
23 merely pointing out this isn't on an FCR basis. I agree
24 that based on this three-year period, what was projected
25 in that three-year period and what occurred is different

1 and that the costs are higher than what was projected.

2 Q. Okay. So let's turn to PPAs. And I want to
3 ask specifically about solar PPAs. All of the energy
4 costs paid by Georgia Power as part of the solar PPAs are
5 recovered through the fuel cost docket; correct?

6 A. (Witness Houston) Yes.

7 Q. And would you agree with me that those costs
8 are captured in MFRP Exhibit 1, which was one of the first
9 things handed to you, at line 27?

10 A. (Witness Houston) Yes. There's a line there
11 for solar PPAs.

12 Q. Okay. Likewise, senior citizen discount,
13 100 percent of that discount is paid for -- 100 percent of
14 the fuel component of that discount is paid for in the FCR
15 docket; correct?

16 A. (Witness Houston) Are you referring to a line
17 item on this schedule?

18 Q. It's Line 39.

19 A. (Witness Berrigan) Yeah. Line 38, senior
20 citizen discount. Income qualified discount, yes. That's
21 in here.

22 Q. And that's paid for by customers as part of
23 the FCR recovery, correct, not out of Georgia Power's
24 profits or some other mechanism; right?

25 A. (Witness Houston) That's correct.

1 I would just say the senior citizen discount
2 is offering a lot of customers that need help, help that
3 they get. And it's a -- it's on a monthly basis. It's
4 something north of \$30.

5 So that's available to our customers. And
6 it's -- you know, an application process. So I think
7 that's an important part of the way we support our
8 customers that need a little bit of additional help.

9 Q. A quick question on hedging.

10 A. (Witness Houston) Yes.

11 Q. You would agree that as we use more gas as
12 projected in the upcoming period, Georgia Power's hedging
13 program will incur more total costs to achieve the same
14 results; correct?

15 A. (Witness Houston) I agree with more natural
16 gas coming on the system. We will incur more costs for
17 natural gas, but I'm not sure what you're referring to
18 about the same results.

19 Q. Well, if you're hedging 40 percent of your
20 natural gas and the total amount of natural gas has grown
21 the cost of that 40 percent will, likewise, grow?

22 That's all I'm asking.

23 A. (Witness Houston) Yes.

24 MS. WHITFIELD: That's all for you,
25 gentlemen. Thank you.

1 MR. HOUSTON: Thank you.

2 MR. BERRIGAN: Thank you.

3 MS. WHITFIELD: And, Commissioners, I'll wait
4 to move in exhibits until after rebuttal, if that's
5 okay.

6 CHAIRMAN SHAW: Okay. Sounds good. Thank
7 you.

8 How much -- just as far as timing, Sierra
9 Club, how much time do you think you have for this
10 panel?

11 Yeah. Let's go ahead and get that. Let's go
12 ahead and move on.

13 MR. BAKER: I have more than that. I have
14 20 or 30 minutes or so, if you want to let me --

15 CHAIRMAN SHAW: Hold on. Let me look here.
16 You said you've got how much for MARTA?

17 MR. BAKER: 20 or 30 minutes.

18 CHAIRMAN SHAW: And you said 15?

19 MS. ARIZA: Are you going to hold me to it?

20 CHAIRMAN SHAW: No, no. Of course not.

21 MS. ARIZA: Okay. Let's go ahead and move on
22 and we'll -- we'll have a hard stop at 12:45. And
23 then -- that way everybody's got time to get down
24 to the cafe before they -- get in line before they
25 close.

1 MS. ARIZA: Perfect. Thank you.

2 Hi, Commissioners.

3 CROSS-EXAMINATION

4 BY MS. ARIZA:

5 Q. Hi, Panel. My name is Isabella Ariza and I
6 represent Sierra Club, SACE, and NRTC.

7 Mr. Houston, you started your summation by
8 stating that with the changes you're proposing today, you
9 expect the bill of the typical residential customer to go
10 down by approximately \$5.78; correct?

11 A. (Witness Houston) Yes. That's correct.

12 Q. Did you calculate how much rates would go
13 down had ratepayers not been paying for the
14 under-recovered balance for the last three years?

15 A. (Witness Houston) Well, the 5.78 is the
16 product of the previous under-recovered balance and the
17 forecast period costs. So taking those two things
18 together gives you \$5.78 decrease.

19 Q. So 5.78 is not what's going to show up in
20 actual bills?

21 A. (Witness Houston) The \$5.78?

22 Q. Yeah. That reduction.

23 A. (Witness Houston) That's a decrease for the
24 fuel component. We also have the storm component, which
25 on a net basis still give a decrease of approximately

1 \$1.37. But for this fuel case, the decrease was \$5.78,
2 which I think is approximately 12 to 13 percent of the
3 fuel rate.

4 Q. Right. My question was: Did you calculate
5 how much rates would go down had customers not been paying
6 the under-recovered balance of FCR-26?

7 A. (Witness Berrigan) Are you proposing that --
8 is your question just if that cost --

9 Q. You made --

10 A. (Witness Berrigan) -- was not recovered or
11 if we had raised rates at some point previously so that
12 balance was then lower?

13 I mean, we did not run hypothetical scenarios
14 to determine what a change in rate could have done to then
15 necessitate the decrease in this proceeding. We're just
16 using the information we had available.

17 Q. Okay. I'm just asking because presumably you
18 weren't recovering that unrecovered balance rates would go
19 down even more?

20 A. (Witness Berrigan) But, again, that's the
21 difference between what we are recovering in rates and the
22 cost of fuel. So for that number to be lower, then we
23 would have needed to have -- one of those variables would
24 have needed to change.

25 And so I think you're asking us to do a

1 hypothetical analysis of how would that number have
2 changed. Is that through change in rates or some other
3 mechanism? And then what does that then result in in
4 this?

5 I mean, that's -- again, we're here to talk
6 about the amount that we believe we'll need to recover.

7 A. (Witness Houston) Yeah. The under-recovery
8 of costs, that was -- that was a real thing. I mean,
9 three years ago we were here on the stand talking about
10 the increase, the under-recovery.

11 So it's just natural that over a three-year
12 period that we asked for on that last rate case, that has
13 been paid down now. So that's part of costs going up and
14 costs going down. So to take one piece and remove it and
15 speculate on what the rate would be, that's not something
16 that we've done.

17 Q. Okay. And regarding what you just mentioned,
18 Mr. Houston, is it possible that that kind of thing
19 happens again?

20 That a dramatic spike in fuel prices leads
21 you to spend substantially more than you had budgeted for,
22 which is what happened three years ago and the reason --
23 the under-recovery?

24 A. (Witness Houston) Well, yeah. Prices
25 certainly go up, prices go down. And, you know, that's

1 why we're a big proponent of -- of the hedge program and
2 increasing the percentage there. Because that would be an
3 additional protection for customers if that thing happened
4 again, which we hope it doesn't.

5 But we -- because we are procuring fuel,
6 which is all fuel, whether that's nuclear, coal, gas, they
7 are subject to some market price changes over time.

8 Q. Okay. Let me ask you some questions about
9 the IFR mechanism that you're proposing to increase from
10 200 million to 300 million; is that correct?

11 A. (Witness Berrigan) Correct.

12 Q. Wouldn't you agree that capping the amount of
13 money of the IFR mechanism protects customers from
14 dramatic rate increases that have not been formally
15 approved by this Commission?

16 A. (Witness Berrigan) Are you asking or is
17 it -- I mean, our belief is that with -- again, with the
18 expansion of costs, we believe that scaling that threshold
19 is appropriate. And, again, from a rate stability
20 perspective, having a larger threshold ensures that rates
21 would be more stable for customers.

22 Q. Okay. I'll ask you about the stability of
23 rates in a second. But at least from an opportunity to
24 provide public comment, isn't it true that capping the
25 amount of the IFR mechanism protects customers from a

1 dramatic rate increase that has not been formally
2 approved?

3 A. (Witness Berrigan) So, I mean, on a monthly
4 basis, we make filings with the Commission to show exactly
5 where our under-recovered/over-recovered balance stands;
6 right?

7 That's a monthly filing. There's a docket
8 that we include that in. You know, in between quarters --
9 the months in between quarters, that's trade secret
10 information. That's publicly available once quarterly
11 information is provided.

12 So the Commission and staff have -- have
13 visibility to those numbers every month. And then all
14 customers have visibility to that information on a
15 quarterly basis for the prior quarter. So, again, it's
16 customers -- and, again, the Commission and staff know
17 exactly where our balance is month to month.

18 Q. But this Commission only decides on whether
19 those costs were prudently incurred every three years or
20 whenever you ask for a fuel docket to be filed; correct?

21 A. (Witness Berrigan) Yeah. I mean, at least
22 in recent history we have come before this Commission on a
23 three-year cadence to ask for, you know, the -- a rate
24 change, whichever direction that may go. And that allows
25 then this type of hearing where we have the ability to

1 discuss the assumptions included and the balances and the
2 costs of fuel.

3 Q. Okay. Regarding the IFR mechanism, staff
4 testified that customers would benefit from Georgia Power
5 modifying rates as a result of the IFR filing when IFR is
6 exceeded.

7 Did you see that testimony?

8 A. (Witness Berrigan) I did.

9 Q. And contrary to staff's suggestion, you state
10 that the company should not be required to implement a
11 rate adjustment after an IFR filing; is that right?

12 A. (Witness Berrigan) That's correct. The
13 current mechanism does not require a -- a rate change
14 proposal. And, again, there's a lot of factors that need
15 to be considered.

16 As I mentioned, and we talked about earlier,
17 there were six times in 2025 where the balance exceeded
18 200 million. There were months in between those where the
19 balance went back under. So I think, you know, there's a
20 lot of factors to consider.

21 Is it a temporary increase or a permanent
22 increase? How close are we to the next fuel case? You
23 know, again, thinking about what do we think the
24 projection looks like? Is it going to continue to move in
25 one direction or another?

1 Those are all factors that should be
2 considered. So a requirement to request a rate change --
3 again, we believe that -- that no requirement and that,
4 again, a notification. And staff and Commission can
5 certainly ask questions on every -- again, every month
6 when we file, even when we're below the threshold.

7 And then certainly when we make a
8 notification, the staff and Commission can again ask
9 questions. And the Commission can choose to make a rate
10 change, even if we don't. I mean, the Commission has the
11 discretion to do what it wants.

12 Q. To implement a rate change, even though you
13 don't ask for it?

14 You're saying they --

15 A. (Witness Berrigan) Again, I'm just saying
16 the Commission has its discretion to make whatever
17 decisions it wants. I mean, we're going to make our
18 filings, put forth our proposal, but the Commission has
19 the latitude to make any decision it chooses.

20 Q. Okay. That -- you did not include that
21 option in your testimony; right?

22 You just said that you did not think it was
23 appropriate to ask for a rate reduction or increase as a
24 result of the IFR filing. I understand that the
25 Commission can do it for --

1 A. (Witness Berrigan) Exactly. All I'm
2 pointing out is that -- again, we don't believe requesting
3 a rate change is necessary. But, again, the Commission
4 can do it. If it wants to, it could.

5 Q. Okay. Because it seems that you're asking
6 for more flexibility around the IFR mechanism, but less
7 obligations to actually achieve what the IFR is intended
8 to do, which is to maintain stable rates. Is that not
9 correct?

10 A. (Witness Berrigan) Okay. I mean, again, I
11 think by expanding it, we are -- we have a wider threshold
12 to operate in between making those formal notifications.
13 Again, we'll make the monthly filings as we always do.
14 And, again, I think this is, again, just in the context of
15 the IFR threshold and those specific required
16 notifications, proposal of a plan, those types of filings.
17 Again, we think that a bigger threshold helps with the
18 rate stability.

19 Q. Even if you don't file for a rate change?

20 A. (Witness Berrigan) Right. I mean, if we're
21 not proposing a rate change, that means that we're keeping
22 rates stable.

23 A. (Witness Houston) And we may be outside the
24 threshold and not propose a rate change because we fully
25 expect that we will come back within it. So there's just

1 a number of factors we need to look at.

2 I mean, we think for the -- for the benefit
3 of our customers, fewer changes is probably better than
4 more changes, so...

5 Q. But then fewer changes means that you don't
6 recover the under-recovery balance --

7 A. (Witness Houston) Well, I mean, we --

8 Q. -- that you've been --

9 A. (Witness Houston) If you've gone over the
10 limit, every month we report we will see that we continue
11 to be over the limit. And if we think that it's
12 increasing, then maybe it is time for a rate change.

13 But it's not a look at it one time and then
14 come back and reassess it six months later. It's a
15 month-to-month thing. And we're looking at new
16 projections of fuel prices, where other things that impact
17 that are coming out.

18 So if we believe, like, we've gone through
19 the limit and it continues to increase, then it would be
20 prudent to suggest a rate change. If we think it's going
21 to come back down towards zero, which is the IFR program,
22 then we would not.

23 MS. ARIZA: Okay. Chairman Shaw, I'm very
24 bad at estimating how long.

25 CHAIRMAN SHAW: Oh, okay.

1 Well, I'll tell you what. This is probably a
2 time where everybody would agree we need a break.
3 What we'll do is we will break.

4 Let's see. We'll give everybody plenty of
5 time. It's 12:45. We'll see everybody back here
6 at 1:40.

7 MS. ARIZA: Okay. Thank you.

8 (A recess was held from 12:45 p.m. until 1:40 p.m.)

9 CHAIRMAN SHAW: All right. Welcome back.
10 Hope everyone had time to grab something to eat.
11 We'll keep things moving here with the panel that
12 we left off with, Sierra Club.

13 Gentlemen, I just want to remind you, you're
14 still under oath, and we'll continue.

15 Go ahead.

16 MS. ARIZA: Thank you.

17 BY MS. ARIZA:

18 Q. Gentlemen, while describing the proposed
19 changes to the IFR -- this is, I think, my last question
20 on IFR -- you state that this modification will provide
21 greater stability for customers by allowing FCR rates to
22 absorb natural price volatility and normal fluctuations.
23 This is page 4, line 7 and 9 of your direct.

24 Do you see that testimony?

25 A. (Witness Berrigan) The statement on page 4,

1 where we're trying to better align the IFR threshold to
2 the magnitude of the total fuel expense incurred by the
3 company?

4 Q. Yes. And where you say that you're trying to
5 absorb natural fuel price volatility and normal
6 fluctuations.

7 A. (Witness Berrigan) Yes. Further down, we
8 say that having a larger threshold would then allow for
9 more fluctuations before an amount exceeds the threshold
10 and a notification would then be required.

11 Q. Okay. What are normal fluctuations in this
12 context?

13 A. (Witness Berrigan) Yeah --

14 Q. Is there a range that you would describe as
15 normal? Sorry.

16 A. (Witness Berrigan) Normal fluctuations.
17 Again, just -- we've talked a lot about natural gas
18 prices, right, in the movement, natural gas prices, other
19 prices or costs related to fuel. Really, and what we're
20 talking about is the ability, with a higher threshold,
21 more room that, as prices move on a month-to-month basis
22 cumulatively over the FCR period, it would, in theory,
23 have fewer opportunities to go outside of the threshold
24 and trigger that -- that IFR notification.

25 Q. Okay. But you don't -- there's no definition

1 of what would be a normal range. There's no -- there's no
2 upper boundary?

3 A. (Witness Berrigan) Okay. I would say that,
4 again, we're talking in terms of going from 2 -- a
5 \$200 million threshold to a \$300 million threshold.

6 Q. I understand the IFR threshold. That's like
7 a 50 percent increase. But there is no -- I -- basically
8 by definition, the volatility of fuel prices cannot be
9 placed within a normal range; is that correct?

10 A. (Witness Houston) Yeah. Well, there's no
11 real normal range of volatility. The volatility is what
12 the volatility is, so we don't describe it as normal or
13 abnormal.

14 Q. Okay. And to address volatility, you
15 mentioned, throughout your testimony, that you hedge and
16 you have the IFR mechanism and other mechanisms in
17 general. But reducing your reliance on gas and coal is
18 not one of the strategies that you list anywhere in your
19 testimony to reduce fuel prices; is that correct?

20 A. (Witness Houston) Yeah, that's not correct.
21 I mean, as we talked about earlier, we have a diverse
22 fleet, so we've got the full range of nuclear, solar,
23 natural gas, coal. So we're not looking to decrease one
24 at the expense of the other. We're looking to manage a
25 whole generation fleet.

1 A. (Witness Berrigan) And to be clear, right, I
2 mean, again, we're using the resources that are available
3 to serve customers. And what we're speaking -- what we're
4 specifically seeking recovery of is the cost of those
5 resources. So this proceeding, we're not proposing any
6 changes to our resource mix; right? That would come
7 through in an IRP proceeding or a certification request
8 through an RFP. Again, this is just seeking a recovery of
9 the costs, the projected costs for fuel.

10 Q. I understand that, but it's just a question
11 of, you don't mention in your testimony that reducing your
12 reliance on gas and coal for the coming three years will
13 be a strategy that you will implement proactively to
14 reduce fuel costs?

15 A. (Witness Houston) Yeah. That's correct.

16 Q. So if gas price volatility continues, which
17 you admit it will, there is no alternative for Georgia
18 Power but to continue buying it; is that correct?

19 A. (Witness Houston) No. I think we have, like
20 we talked about before, a diverse fleet, so a number of
21 different generating facilities are quite different fuel.
22 So whether that's nuclear, gas, PPAs, coal, many other
23 things, I think -- I think we have a fleet that's the envy
24 of many utilities. So that -- that is part of what the
25 hedge is. So we're not picking and choosing.

1 We're continuing to build out a whole bunch
2 of things. For -- for argument's sake, we are looking to
3 add a lot of battery storage here for the next five to six
4 years, a significant amount. We're looking to add more
5 solar. I think another 4,000 self-built megawatts of
6 solar here through 2035. So we're looking at all of the
7 above technologies.

8 Q. But you still testify that for the next three
9 years, gas will be the largest resource, single resource
10 that you use, correct, with 40 percent?

11 A. (Witness Houston) Yes. If you look at the
12 test period in terms of gigawatt hours generated, natural
13 gas is the largest. But if you put together of a --
14 renewable sources, nuclear, solar PPAs, hydro, that
15 actually is larger than the expected generation from
16 natural gas.

17 Q. If you combine all those?

18 A. (Witness Houston) That's right.

19 Q. Okay. You recognized today and in your
20 testimony this extreme volatility of gas, and that it's
21 not going anywhere; correct? You expect it to continue,
22 and you describe the many reasons why it might continue.

23 A. (Witness Houston) Yeah. I think natural gas
24 has been volatile in terms of certain price changes.
25 There's no reason to believe that that's going to change

1 anytime soon.

2 Q. Would you agree that it is important for the
3 company to bring this up during IRP proceedings, since
4 this information could lead the Commission to understand
5 and have a more informed view of other alternative
6 portfolios that maybe rely less on natural gas?

7 A. (Witness Houston) Yeah, not -- obviously,
8 they're a participate -- participant in the IRP
9 proceedings. I mean, I think that that -- those are
10 considered in the IRP proceedings, that the nature of the
11 generation, the fuel to put through it, the cost, a whole
12 bunch of other considerations. I mean, I know those are
13 very involved proceedings, and so I think that those are
14 all covered in those proceedings.

15 Q. But you said in your response to discovery --
16 and I have it here, if you don't recall, but you might
17 recall -- that you didn't think it was a good idea to
18 align the rate case cycle with the IRP, and the rate case
19 is every three years.

20 Do you recall that?

21 A. (Witness Houston) I -- I mean, if you have
22 the data request, it would be helpful to look at.

23 Q. Yes.

24 For the record, this is the company's
25 response to STF-JKA-2-2. And subsection E asks: Has the

1 company considered aligning future FCR proceedings with an
2 IRP or rate case? Why or why not?

3 And your response is on the back of the page.
4 It's the last one.

5 A. (Witness Berrigan) So could you -- sorry.
6 Could you repeat your question one more time?

7 Q. My question is first, well, what you said
8 here is that you don't intend and you don't think it would
9 be a good idea to align IRPs and rate cases with the fuel
10 docket; correct?

11 A. (Witness Berrigan) What we describe here is
12 that there's an administrative burden in putting all of
13 those proceedings together. I mean, currently we have the
14 IRP process; right? Every three years we file an IRP.
15 Every three years we file a rate case. And just as a
16 reminder, the purpose of the IRP is to look at the
17 generation resources, the generation mix, to determine
18 which units and additions to the fleet the company can
19 move forward with.

20 The rate case is then designed to set rates
21 to recover those costs exclusive of fuel, which is then,
22 you know, part of this proceeding. And so, you know,
23 again, trying to sort of sequentially align those and not
24 have them all on top of each other, we feel, like, kind of
25 provides the right level of review, due diligence for the

1 process, and not overwhelm anyone with having kind of all
2 of that stacked on top of each other.

3 And so then fuel kind of comes behind all of
4 those other proceedings.

5 VICE-CHAIRMAN MCDONALD: And we don't have
6 the staff to put all that together either.

7 A. (Witness Berrigan) Yes, sir.

8 BY MS. ARIZA:

9 Q. Right. And I'm sympathetic to those
10 administrative difficulties, but hypothetically only,
11 wouldn't you agree that there's benefits in assessing the
12 convenience of adding gas to the grid while you're also
13 evaluating the costs that that that means to ratepayers?

14 A. (Witness Houston) I mean, I think that's
15 what we're doing in this proceeding. We're by no means
16 saying that we should not have regular proceedings to go
17 through the IRP, the fuel and the rate case. We just
18 can't do them all at the same time. So we -- the
19 Commission should keep up the same level of scrutiny that
20 they have always done, and obviously we're a party to
21 that.

22 Q. Okay. On page 15, lines 15 through 23 of
23 your testimony, you state that the total projected fuel
24 costs for the test period is approximately 1.4 billion, or
25 25 percent more than the projected fuel cost for the

1 FCR-26 test period.

2 Do you see that testimony?

3 A. (Witness Berrigan) You said page 15?

4 Q. Yes.

5 A. (Witness Berrigan) That the fuel costs are
6 approximately 1.4 billion more in FCR-26 more than what
7 was in FCR twenty -- in 27 is more than it was in 26?

8 Q. It's 25 percent more, yes.

9 A. (Witness Berrigan) That's correct.

10 Q. Is there a percentage of price increase that
11 you'd be willing to set as a cap? For example, if FCR-28
12 ends up being 50 percent or 80 percent more than FCR-27,
13 would the company consider doing anything differently?

14 A. (Witness Houston) But what this -- this
15 increase is to meet the increase in load. So this is fuel
16 that's going through generating units, new generating
17 units, purchase power. So this here is fuel to meet that
18 load. So it's not -- going up is not necessarily the
19 problem. It's the rate that we're looking at.

20 I expect that this will continue to go up as
21 we have more load, more large load, more benefits in the
22 state, more growth in Georgia. So capping that, I don't
23 think, necessarily makes sense.

24 A. (Witness Berrigan) And ultimately there will
25 be more revenue also; right? As costs are going up,

1 revenues are also going up.

2 Q. Not for the fuel docket, though.

3 A. (Witness Berrigan) Again, you're asking sort
4 of just looking at these numbers. I mean, yes, when we
5 have more load, more costs, there's more -- there's more
6 revenue.

7 Q. For the rate case, correct, not for fuel at
8 all? Since those are passed through, I think you --

9 A. There will be more fuel billings for the FCR
10 customers and for the large load customers. So that's the
11 revenue we are talking about to match with the fuel costs.

12 Q. And switching now to coal, you said some of
13 the coal questions should be saved for rebuttal. Does
14 that include the must-run designation that is part of your
15 direct?

16 A. (Witness Houston) Yes, it does.

17 Q. Okay. Then let me switch to -- I think those
18 are also for the rebuttal panel.

19 MS. ARIZA: Okay. No further questions.

20 Thanks.

21 MR. HOUSTON: Thank you.

22 MR. BERRIGAN: Thank you.

23 CHAIRMAN SHAW: MARTA.

24 Mr. Baker, how are?

25 MR. BAKER: Doing well, Mr. Chairman. Thank

1 you very much.

2 CROSS-EXAMINATION

3 BY MR. BAKER:

4 Q. Good afternoon, Panel.

5 A. (Witness Berrigan) Good afternoon.

6 A. (Witness Houston) Good afternoon.

7 Q. I've got a few questions here for you, I hope
8 you can help me with. Just a clarification question to
9 start off with.

10 You mentioned in a couple of places in your
11 testimony, you reference wholesale customers. Who are the
12 wholesale customers that you're referencing in your -- in
13 your testimony?

14 If you want to look for specifics, it's at
15 page 12, line 16, page 16, line 19.

16 Are these utility customers?

17 A. (Witness Houston) Yes, some of them local
18 co-ops in the state of Georgia. So it's a -- it's a mix,
19 but it's load-serving entities predominantly.

20 Q. Utility companies, EMCs, co-ops?

21 A. (Witness Houston) Yes. That's right.

22 Q. All right. And are these wholesale contracts
23 with other utilities long-term contracts or are they short
24 term?

25 A. (Witness Houston) I don't know, off the top

1 of my head, but I'm -- they're long term, primarily, block
2 sales of capacity and energy, so...

3 Q. Really? Okay. When you -- if you know, do
4 you have an idea what your long-term definition is? Is it
5 a year? Two years? Three years?

6 A. (Witness Houston) Longer than one year.

7 Q. Longer than one year? Okay.

8 And in your testimony you mentioned the --
9 that you're forecasting a 12 percent increase. Why is the
10 total demand for electricity projected to increase by
11 12 percent for the first 12 months of the FCR-27 period?
12 And that is at page 8, line 14.

13 A. (Witness Houston) Yes. This is the
14 continued growth in Georgia. This is commercial
15 industrial companies, as we have built out an industry, as
16 we have data centers coming into the state, as we have
17 growth. That is really what's driving this increase in
18 load. And we can certainly see it continuing through the
19 test period as well.

20 Q. This is primarily data center growth?

21 A. (Witness Houston) No, I would not say the
22 test period primarily at all.

23 Q. Would you say it's more than 50 percent is
24 data center?

25 A. (Witness Houston) I don't know the answer to

1 that. I mean, what I would say is that fuel is recovered
2 through non-RTP and RTP rates. So non-RTP is the
3 residential customers. RTP rates are a combination of
4 industrial and commercial. Data centers are an element of
5 those RTP rates.

6 Q. All right. All right. Let me clarify my
7 question, since you've -- is the 12 percent demand related
8 to -- primarily related to data center growth?

9 A. (Witness Houston) I don't know if I can say
10 "primarily." It's an element, certainly, but I don't know
11 about primarily.

12 Q. So it's not more than 50 percent?

13 A. (Witness Houston) I don't know the answer to
14 that.

15 Q. In response to a question Ms. Whitfield asked
16 you earlier about the CBL component for RTP, you mentioned
17 that the new growth was -- I think you used a figure of
18 98 percent was going to be data, commercial, industrial,
19 data-center driven?

20 A. (Witness Houston) Yes, that's right. That
21 was figures that I gave earlier where, for the test
22 period, we're going to have an additional
23 36 million-megawatt hours generated. 98 percent of that
24 is commercial and industrial.

25 Q. And you've also mentioned that there would be

1 a no-CBL component to that, as to that RTP load; is that
2 correct?

3 A. (Witness Houston) Under the rules and regs
4 for large-load contracts, there is a MAC rate that is
5 being utilized, and I am not an expert in the way those
6 tariffs are constructed. Mr. Evans will be coming on for
7 the rebuttal testimony. He can talk about the design of
8 those tariffs.

9 Q. Do you know if there are some of the new
10 tariffs that are being utilized that do not have a CBL
11 component?

12 A. (Witness Houston) I would say, in this case,
13 we are not proposing any changes to existing tariffs or
14 new tariffs. So whatever tariffs are being built to
15 customers have been approved by this Commission
16 previously.

17 Q. So there is -- there are -- there are some
18 tariffs that might have a -- not have a CBL component to
19 it?

20 A. (Witness Houston) I would like you to ask
21 Mr. Evans that question.

22 Q. Is that -- is he part of your rebuttal panel?

23 A. (Witness Houston) Yes. That's right.

24 Q. I'll do that.

25 At page 9, line 27, you mentioned coal

1 generation was 141 percent higher than budgeted because it
2 was used to serve additional load during the historical
3 period.

4 What was that additional load that you
5 referenced?

6 A. (Witness Houston) That is just a
7 continuation of the load that we have talked about here
8 with industrial companies. Commercial companies continue
9 to move to the state of Georgia, Georgia being a top state
10 for doing business, attracting industry here. That load
11 is being -- that's what that load is that's serving those
12 customers.

13 Q. But that's a 141 percent increase. That's a
14 substantial increase in load over a period of time.

15 A. (Witness Houston) Yeah. That's a great
16 observation, great question. What I would say is in the
17 prior budget, just coming out of Covid, and some of the
18 stress that was around coal generation and the prices with
19 transportation and train sets, in the budget was -- had a
20 low level of generation because the price was high, so it
21 wasn't a dispatch nearly as much. But as we move through
22 time and prices stabilized, then they got cheaper and was
23 dispatched a little bit more.

24 Q. Why do the fuel costs -- why do fuel costs
25 increases -- why does fuel cost increase an additional

1 \$500 million for the second 12 months of the test period,
2 from 3.3 billion to 3.8 billion?

3 A. (Witness Houston) As we talked about, that's
4 a function of increasing load, and it's a function of more
5 industry and commercial customers coming to the state,
6 ramping up as customers of signed contracts, as they're
7 ramping up their load to expectations. That is just a
8 continuation of increased load.

9 Q. When you referenced commercial customers, are
10 those data centers that you're referring to?

11 A. (Witness Houston) Yeah. Data centers are an
12 element of commercial customers, yes.

13 Q. And there has been some discussion about
14 volatility of natural gas prices, and based on current
15 situation here, let me ask you: Have you changed your
16 natural gas price forecast considering the war in Iraq?
17 Is that a factor that you have considered or will
18 consider?

19 A. (Witness Houston) Yeah. We -- we certainly
20 look at forecasts continually. We have not updated that
21 forecast because we have not seen an increase in natural
22 gas prices because of that war. So we have not updated
23 it. But certainly knowing that prices can change, we
24 certainly continue to look at it. And it's something we
25 continue to consider.

1 Q. Okay. What would trigger a review? And I
2 said "Iraq." I think it should be the war in Iran.

3 A. (Witness Houston) Yes.

4 Q. What would trigger a review?

5 A. (Witness Berrigan) And to clarify, when you
6 say "a review," a review of what?

7 Q. Your forecast, your natural gas price
8 forecast. What has -- what would happen? I mean, what
9 has to happen before you-all sit down around the table and
10 say, we need to look the -- you know, at what could happen
11 here in the future and how do we prepare for it?

12 A. (Witness Berrigan) So as it relates to the
13 request, right, we used our 2026 energy budget. That
14 energy budget uses natural gas prices as of September.
15 That's our annual process. That's every year we go
16 through a -- a fulsome process to determine our energy
17 budget. That's what was used in this case.

18 We did a sensitivity analysis, and it's
19 included in our rebuttal testimony where we then compared
20 natural gas prices using April debts, so at the end of
21 March, and looked at those prices; right? Same -- same
22 methodology, same type of information, but went from
23 September to March.

24 We include in our rebuttal testimony that
25 prices have decreased slightly, right, but if you consider

1 price of natural gas going down a little bit, the
2 under-recovered balance has changed from what we
3 originally included and on a net basis, it is a slightly
4 higher than it -- than it would have been.

5 And so we're considering, we're looking at
6 that information, but, you know, again, not -- it is a
7 long process to flow an assumption all the way through the
8 energy budget.

9 Again, it's a sensitivity analysis to ensure,
10 I think, as you're asking, that we are -- that what we
11 have asked for and what we've included is reasonable,
12 based on the fact that, again, we prepared this
13 information months ago.

14 COMMISSIONER HUBBARD: Quick question. Are
15 you just looking at spot wholesale natural gas
16 prices, or are you also looking at the futures
17 curves?

18 MR. HOUSTON: No. Certainly looking at the
19 futures curve. So we'll go and -- we'll go to the
20 NYMEX market, and we'll look at the price points
21 out for the next three years. And we'll do that
22 over a period of 20 days and take an average of how
23 those curves are moving over time.

24 So that's how we develop the forward curve.
25 So certainly not spot price. You're right,

1 Commissioner, that that's just the current price.
2 You've got to look at the future prices as well.

3 COMMISSIONER HUBBARD: Is that forward
4 projection just a NYMEX curve over a few different
5 dated periods, or are you also using any kind of
6 fundamentals --

7 MR. HOUSTON: We do for the -- for the
8 near-term, for the prompt period, we certainly do
9 use indicator prices in the market, because that's
10 what we would trade at. For the -- going out a
11 little bit further, you're exactly correct. We
12 would look at fundamentals, look at EIA studies and
13 things similar to that.

14 COMMISSIONER HUBBARD: What's that transition
15 period? When does that happen, when you fade away
16 from prompt futures to the fundamentals?

17 MR. HOUSTON: Subject to check, out to four
18 or five years is when we would go to the
19 fundamentals.

20 COMMISSIONER HUBBARD: So this is a futures
21 based, the projected period is all just based on
22 futures?

23 MR. HOUSTON: Yes, exactly, correct. Yes.

24 BY MR. BAKER:

25 Q. Turning now to your discussion of the Transco

1 Transportation contract for plants Bowen and Wansley,
2 page 19 of your prefiled testimony. Are the new combined
3 cycle plants at Bowen and Wansley being built primarily to
4 serve these new large load customers?

5 A. (Witness Berrigan) Those are two plants that
6 were, again, picked through -- identified in the IRP that
7 there was a need for additional generation, went through
8 the RFP process. Those were two units that were
9 selected -- or two projects that were selected, and those
10 were certified in December by the Commission to move
11 forward with.

12 Again, we serve the system, right, we're not
13 looking at adding generation for any specific customer or
14 types of customers. We're looking to add resources to
15 serve the system.

16 Q. I understand that, but if there weren't a
17 large increase in data center demand, that these units
18 would not have been built; is that correct?

19 A. (Witness Houston) Yeah. I mean, these units
20 obviously went through the IRP, the certification
21 supplemental proceedings in response to seeing load
22 forecasts increase. And, yes, industrial customers, data
23 center customers, they're all part of the mix. They're
24 all part of what makes up that load increase.

25 Q. And are the Transco capacity payments

1 incorporated into the new FCR-27 rates?

2 A. (Witness Berrigan) I mean, the portion
3 that's included for the test period is in -- is in our
4 costs.

5 Q. So that's yes?

6 A. (Witness Berrigan) Yes.

7 Q. And isn't it true that capacity payments are
8 only paid by base rate customers?

9 A. (Witness Houston) What contracts are you
10 referring to?

11 Q. I'm talking about just the general recovery
12 of cost for capacity payments. Those are only recovered
13 from base rate customers; is that correct?

14 A. (Witness Houston) If you're talking -- well,
15 what I'm familiar with is PPA contracts. They have a
16 capacity element and an energy element. And yes, in that
17 case, you're correct. The capacity for PPA is in base,
18 and then the energy is in fuel.

19 Q. Okay. I'm talking about not PPA. I'm
20 talking about Transco capacity pipeline payments, and
21 those are only recovered through base rates; is that
22 correct?

23 A. (Witness Berrigan) And, again, when you say
24 "base rates," I think of the base rate case. I don't
25 think of the fuel case. Again, we discussed earlier that

1 firm transportation, the cost to deliver fuel to our
2 facilities is a fuel cost. So it's included in the FCR.

3 Q. Got it. Got it. But these costs, the
4 pipeline capacity payments -- let me rephrase that -- are
5 only recovered from non-RTP customers?

6 A. (Witness Berrigan) As we discussed earlier,
7 I think you're starting to get into the mechanics of the
8 RTP rate and how that's calculated. And again, we'll have
9 in the rebuttal panel, Mr. Evans, who's prepared to talk
10 about RTP and the methodology.

11 Q. And the recovery related to RTP and marginal
12 rates?

13 A. (Witness Berrigan) He'll be able to speak to
14 RTP and the mechanism and the recovery of costs.

15 Q. Okay. If you want to refer to page 21 of
16 your testimony, line 15, said that the company projected
17 using 461 million MMBtu's annually during the FCR-26
18 period. Approximately, how much did it actually use
19 annually during the FCR-26 period?

20 A. (Witness Houston) Yeah, I don't think we
21 have that information.

22 Q. And do you know if it's even close? Is it
23 close to 461 million?

24 A. Yeah. Without knowing the number itself, I
25 certainly expect it would be close to the 461 million.

1 Q. I'm not going to hold you -- you know,
2 rounding to a 10 million -- 10 million, 10 million BTUs or
3 so. That's fine with me. So it was close to it. All
4 right. All right.

5 Now, the company is projecting using
6 522 million BTUs -- million BTUs annually during the
7 FCR-27 period. Wouldn't that mean that the company is
8 asking to increase its hedging program by 128 million, 800
9 thousand -- million BTUs annually for the FCR -- from the
10 FCR-26 period?

11 A. (Witness Houston) I'm sorry. How are you
12 doing that calculation? I can say simply we're requesting
13 the hedged percentage to go from 40 percent to 60 percent.

14 Q. Well, in your -- in your prefiled testimony,
15 you're saying that -- you're projecting use in the FCR-27
16 period of 522 million. That's in your testimony. And you
17 are saying that you are close to -- I'm not holding you to
18 exact, but you are close to using 461 million BTUs during
19 the FCR-26 period. Doing the math --

20 A. (Witness Houston) Okay. Doing the math?

21 Q. Yes. It's 128,800,000, million BTU
22 difference. I'm no mathematician, but I think I got that
23 right.

24 A. (Witness Houston) Well, I think these
25 numbers are for the total test period. These are -- these

1 are the totals over a two-year period, so your number may
2 be doubled up.

3 Q. Well, aren't these -- both these numbers for
4 the respective test periods?

5 A. (Witness Houston) Well, it says projected on
6 the test period. FCR-27 is 522 million, compared to
7 461 million in the test period for FCR-26.

8 Q. Okay. So for the entire projected test
9 period, that would be an increase of 128 million,
10 approximately?

11 A. (Witness Houston) No, because this is the
12 test period.

13 Q. I know.

14 A. (Witness Houston) You may be looking at a
15 one-year basis.

16 Q. One year. No, no, no.

17 A. (Witness Berrigan) Is your question, are we
18 intending to burn more natural gas?

19 Q. Yes.

20 A. (Witness Berrigan) Yes. I mean, we --

21 Q. A significant -- a significantly amount.

22 A. (Witness Berrigan) We've talked about the
23 fact that we are intending to burn more natural gas. We
24 have more load, and there will be more natural gas based
25 on the resource mix that we have available to provide

1 energy to our customers.

2 Q. And, also, wouldn't that -- if you're asking
3 for an increase in the amount that you can hedge from
4 40 percent to 60 percent, wouldn't this increase in the
5 amount of gas that you're actually going to be using or
6 projected to be using have an enormous impact on the
7 amount of gas that's being hedged on the system?

8 A. (Witness Houston) Yes. We will be hedging
9 more natural gas, yes.

10 Q. Now, turning to the renewable resource
11 procurement cost recovery. If all the RFP-related costs
12 are not recovered by bid fees or winner fees, shouldn't
13 these fees be increased rather than passing those costs to
14 all ratepayers?

15 A. (Witness Berrigan) Sorry. Could you ask
16 your question one more time?

17 Q. I can. If all the renewable -- if all the
18 RFP-related costs are not recovered by bid fees or
19 winner's fees, shouldn't those fees be increased rather
20 than passing those costs to all ratepayers through the
21 fuel rider?

22 A. (Witness Berrigan) So I guess I sort of hear
23 two things in there. One, right, if you think about the
24 cost, right, the -- what we're allowed to charge, the bid
25 fees and winner fees today, we believe that those would

1 cover the cost; right? And to the extent that there's a
2 shortfall in the revenue and the costs are higher, then
3 that -- that net cost is part of the FCR. To the extent
4 the revenues exceed the costs, then that excess stays in
5 the FCR.

6 To the extent there's a decision to change
7 the amount that's charged in two bidders and two -- as
8 part of those RFP programs, the Commission has the
9 discretion to change the amount that we would -- we would
10 ask customers to pay for those.

11 So, again, we're looking at what's approved,
12 what we can ask for, and then using that to cover the
13 costs.

14 Q. Well, when was the last time that the
15 renewable resource procurement bid fees or winner's fees
16 were adjusted?

17 A. (Witness Berrigan) I don't have -- I'm not
18 aware of when the last time that was adjusted.

19 A. (Witness Houston) You know, we're not
20 involved in the procurement process or the bidding
21 process.

22 Q. All right. Understood. Should there be a
23 cap on the recovery of bid fees and winner's fees so that
24 the unrecovered excess is not passed through the FCR?

25 A. (Witness Berrigan) Are you asking if there

1 should be a cap on the amount we can collect from
2 customers, or a cap on the cost?

3 Q. Cap on the cost. Well, excuse me. You're
4 correct. Cap on the -- recovery through the customers.

5 A. (Witness Berrigan) So again, the -- in
6 our -- in our budget and what we're -- what we've included
7 in this request, we believe that the amount we collect
8 will more than cover the cost. So, again, this is
9 providing a downward impact on our rate request for
10 customers. Again -- and this is the -- you know, these
11 RFPs, renewable RFPs, these are programs and ultimately
12 providing renewable benefits to customers. And so we're
13 just trying to match the revenue and the cost together.

14 Q. Understood.

15 A. (Witness Berrigan) And, yeah, I mean, again,
16 I believe that the revenue, as it's currently designed,
17 covers the cost, and it's appropriately covering the cost.

18 Q. Based on your belief. And I hope you're
19 right, is that you're covering the cost, but,
20 hypothetically, if you don't cover the cost, should those
21 unrecovered costs then be flowed through the FCR?

22 A. (Witness Berrigan) It's a mechanism that
23 goes in either direction; right? If the revenues are
24 greater, then that benefit stays with the customers. If
25 the -- if the revenues aren't enough, then -- then that

1 incremental cost is part of the FCR. It goes in either
2 direction.

3 Q. General question, is the cost of the hedging
4 program recovered from all rate classes?

5 A. (Witness Houston) Yes. Yes.

6 Q. The marginal customers are paying hedging
7 costs?

8 A. (Witness Houston) Yeah. The hedging goes
9 into the fuel cost recovery, and that's from all
10 customers.

11 Q. RTP customers, marginal customers --

12 A. Yes.

13 Q. -- are all paying a portion of the hedging
14 cost?

15 A. (Witness Berrigan) Again, I think you're
16 getting into how costs are recovered from our TP
17 customers, and I believe that's a question better suited
18 for the rebuttal panel.

19 Q. Okay. So y'all -- you don't -- I appreciate
20 that.

21 A. (Witness Houston) But the hedge gains and
22 losses go to the cost of the fuel, so that is recovered by
23 all customers.

24 MR. BAKER: Thank you, gentlemen, for your
25 time. I appreciate it.

1 Thank you, Commissioners.

2 CHAIRMAN SHAW: Resource Supply Management.

3 (No response.)

4 Redirect?

5 MS. PRYOR: Just a few questions.

6 REDIRECT EXAMINATION

7 BY MS. PRYOR:

8 Q. Mr. Collado asked you about the amount of
9 growth attributed to large loads. I believe the figures
10 he used were 3.- -- or 34.9 million megawatt hours out of
11 36 million megawatt hours being due to large loads, or
12 approximately 98 percent.

13 Do you recall that?

14 A. (Witness Berrigan) Yes.

15 A. (Witness Houston) Yes.

16 Q. And to clarify those numbers, the
17 34.9 million megawatt hours of growth is for all C&I
18 customers, not just RTP; correct?

19 A. (Witness Houston) That's correct.

20 Q. And several of the questioners asked you
21 about fuel hedging. And just to clarify this point, if
22 there are hedging losses, that signals that gas prices are
23 lower; correct?

24 A. (Witness Houston) Correct.

25 A. (Witness Berrigan) Correct.

1 Q. Which is a benefit to customers; right?

2 A. (Witness Houston) Yes.

3 Q. And the company having price stability helps
4 set FCR rates appropriately to keep them stable; is that
5 right?

6 A. (Witness Berrigan) Correct.

7 Q. And that helps prevent potential IFR triggers
8 when fuel prices go up; right?

9 A. (Witness Berrigan) Correct.

10 MS. PRYOR: Okay. Thank you, gentlemen. No
11 further questions. I would just ask that their
12 testimony be moved into the record.

13 CHAIRMAN SHAW: So marked.

14 MS. PRYOR: Thank you.

15 CHAIRMAN SHAW: All right. Gentlemen, thank
16 y'all.

17 MS. PRYOR: Thank you.

18 CHAIRMAN SHAW: We're going to keep things
19 moving. And as they get off the stand, we'll ask
20 the PSC to call up your panel.

21 MR. COLLADO: Thank you, Mr. Chairman. At
22 this time, I'd like to call the panel of Tom
23 Newsome, Bill Hayet, Anthony Sandonato, and Leah
24 Wellborn to the stand.

25 Thereupon,

1 TOM NEWSOME,
2 PHILIP HAYET,
3 ANTHONY SANDONATO,
4 LEAH J. WELLBORN,
5 having been duly sworn, testified as follows:

6 DIRECT EXAMINATION

7 BY MR. COLLADO:

8 Q. Mr. Newsome, can you state your full name,
9 title and job responsibilities for the record, please.

10 A. (Witness Newsome) Tom Newsome, director of
11 utility finance for the Georgia Public Service commission.

12 Q. Thank you.

13 Mr. Hayet, same question?

14 A. (Witness Hayet) Philip Hayet, Vice
15 President, J. Kennedy and Associates.

16 Q. Ms. Wellborn?

17 A. (Witness Wellborn) Leah Wellborn, director
18 of consulting at J. Kennedy and Associates.

19 Q. Thank you.

20 And Mr. Sandonato?

21 A. (Witness Sandonato) Anthony Sandonato. I'm
22 an outside consultant for J. Kennedy and Associates.

23 Q. Mr. Newsome, on April 9th, of this year, did
24 you prefile or cause to be prefiled 74 pages of testimony
25 in question-and-answer format as well as five exhibits
labeled STF-NHSW-1 through 5?

A. Yes.

1 Q. And if you were asked the same questions
2 today under oath, would your answers be the same as those
3 in your prefiled testimony?

4 A. Yes. However, the company filed an errata
5 last week and that would have changed some of the numbers
6 in our Table 19 but it would not have changed our
7 conclusions.

8 MR. COLLADO: Thank you.

9 Mr. Chairman, the court reporter has been
10 given a copy of the prefiled direct testimony with
11 the exhibits. I would ask that the direct
12 testimony be entered into the record as if it was
13 given here today.

14 CHAIRMAN SHAW: So marked.

15 (Whereupon, the prefiled direct testimony of
16 Tom Newsome, Philip Hayet, Anthony Sandomato and
17 Leah Wellborn follows:)

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF: GEORGIA POWER
COMPANY'S FUEL COST RECOVERY
APPLICATION (FCR-27)**

DOCKET NO. 56765

**DIRECT TESTIMONY
AND EXHIBITS
OF
TOM NEWSOME, PE, CFA
PHILIP M. HAYET
ANTHONY SANDONATO
LEAH J. WELLBORN**

**ON BEHALF OF THE
GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF**

PUBLIC DISCLOSURE

April 9, 2026

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I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAMES AND BUSINESS ADDRESSES.

A. My name is Tom J. Newsome. I am the Director of Utility Finance with the Georgia Public Service Commission ("Commission"). My business address is 244 Washington St., Atlanta, Georgia, 30334.

A. My name is Philip Hayet. I am a Vice President and Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

A. My name is Anthony Sandonato. I am an outside consultant to Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

A. My name is Leah Wellborn. I am a Director of Consulting and Principal at Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. MR. NEWSOME, WHAT ARE YOUR PRIMARY RESPONSIBILITIES WITH THE COMMISSION STAFF?

A. I am responsible for economic, financial, and cost of equity analysis and evaluations at the Commission.

Q. WHAT CONSULTING SERVICES DOES KENNEDY AND ASSOCIATES PROVIDE?

A. Kennedy and Associates provides consulting services related to electric utility system planning, resource planning, fuel auditing, production cost modeling, ratemaking, finance, accounting, and industry policy issues.

Q. PLEASE PROVIDE SUMMARIES OF YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. Summaries of our education, experience, professional certifications, and testimony appearances are provided in Exhibits STF-NHSW-1, STF-NHSW-2, STF-NHSW-3 and STF-NHSW-4 for Mr. Newsome, Mr. Hayet, Mr. Sandomato, and Ms. Wellborn, respectively.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In this testimony, we present Staff's analysis and recommendations concerning Georgia Power Company's Fuel Cost Recovery ("FCR-27") filing. We address the Georgia Power Company's ("Georgia Power" or "the Company") four requests in their direct testimony which are summarized below:

- To set projected fuel rates to recover fuel costs as projected for the Company's FCR-27 test period (June 2026 through May 2028).
- To increase the threshold amount by which the Company can trigger a rate adjustment through the Interim Fuel Rider ("IFR") mechanism from the current amount of \$200 million to \$300 million.
- To expand the natural gas hedging program; and,
- To authorize Georgia Power to recover all Renewable RFP (utility scale and distributed generation) and renewable subscription program-related costs not otherwise recovered by the Company through Bid Fees and Winner's Fees, be recovered through the fuel clause¹

We also address other fuel cost recovery issues, such as impacts of new large load customers on fuel cost recovery.

II. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

¹ Direct Testimony of Adam D. Houston and Matthew S. Berrigan p. 26, ll. 4-14.

A. We offer the following findings/recommendations:

- 1) Staff recommends a **\$10,024,570** adjustment (reduction) to the fuel balance as shown in Table 1. In general, these issues concern generator and transmission outages, excess carrying costs, and Real Time Pricing (“RTP”) fuel credit calculations related to natural gas firm transportation (“FT”) and non-dispatchable contracts. Staff provides a historic impact quantification to provide an indication of the impact of issues investigated; however, Staff is only recommending adjustments as shown in the “Recommended Adjustment” column to the right.

Table 1: FCR Cost Disallowance Recommendations

	Historic Impact (Estimated)	Recommended Adjustment
McDonough 5B Generator Outage	\$ [REDACTED]	\$ [REDACTED]
McDonough 6B Generator Outage	\$ [REDACTED]	\$ [REDACTED]
McIntosh Generator Outage	N/A	
[REDACTED] Transmission Issue Outage	\$ [REDACTED]	
Excess Carrying Costs	\$8,221,787	
RTP Fuel Credit (FT) ²	\$57,571,357	
RTP Fuel Credit (Take-or-Pay) ³	N/A	
Total	\$76,006,714	\$10,024,570

- 2) Staff disagrees with the Company’s proposed changes to the Interim Fuel Rider (“IFR”); and instead recommends the IFR remain unchanged at the \$200 Million threshold. Staff further recommends that when the threshold is exceeded, the Company not only make an informational filing, but also be required to propose an adjustment to fuel rates to minimize cumulative impacts until a comprehensive fuel case can be filed and reviewed. However, Staff recommends any proposed IFR changes to fuel rates occur no more frequently than once every three months.
- 3) Staff recommends in the future, costs in excess of revenues associated with Georgia Power’s Renewable RFP (utility scale and distributed generation) and renewable subscription programs be excluded from recovery through the fuel clause. Any of these costs in excess of revenues should be placed in a regulatory asset and addressed in the next base rate case.
- 4) The Company proposed that no specific date be set for the filing of the next FCR case (FCR-28). The Commission should establish a date for the next FCR filing. Staff recommends the Company file FCR-28 in February 2029 for new rates to go into effect June 1, 2029, on the traditional three-year cycle.
- 5) Staff recommends the natural gas hedging program be terminated as it does not

² STF-JKA-3-11b.

³ Pending STF-JKA-6-1.

1 ensure stable fuel rates for customers and has increased fuel cost for customers over
2 time. Should the Commission allow the Company to continue its hedging program,
3 Staff recommends the volumes and lead time be reduced to protect customers given
4 the larger burn volumes expected in the future, and that the Company include detailed
5 transaction level information in its annual reports to allow for further evaluation
6 ahead of the Company's next FCR proceeding.

7 6) Staff recommends the Company continue filing semi-annual fuel reports as it has in
8 the past. Additionally, Staff recommends that hourly energy and cost information be
9 included to allow for an examination of Georgia Power's average hourly fuel costs
10 and the amount of RTP revenue credited to fuel revenues.

11 7) Staff identified discrepancies in the treatment of RTP revenue used to offset FT costs
12 recovered in fuel rates. Staff recommends the Company address the FT issues in
13 rebuttal testimony and modify the RTP fuel credit methodology to include an FT cost
14 component calculated like the capacity and transmission components to ensure that
15 FT costs are shared by all load served during peak events.

16 8) Staff found similar issues with take-or-pay contracts, and recommends the Company
17 address the take-or-pay contract issues in rebuttal testimony. Staff also recommends
18 the Company modify the RTP fuel credit methodology to include take-or-pay
19 contract costs in each hour to ensure that all generation costs that flow through the
20 fuel balance are shared by all load served by the Company.

21 9) Further regarding RTP, Staff recommends that the Commission open an investigation
22 docket to consider if the RTP fuel credit methodology and the Company's application
23 of the methodology going forward is sufficient to protect non-RTP customers from
24 cost-shifts associated with future load growth.

25 10) Staff recommends that in Rebuttal Testimony, the Company should recompute the
26 Part-B rate with an updated estimate, as the Company's filed \$ [REDACTED] million Part A
27 balance estimate may be smaller than the balance derived at the time of Rebuttal.

28 11) Staff recommends the Company explain in Rebuttal Testimony its coal inventory
29 management strategy and provide sufficient evidence to prove that the coal units were
30 not operated uneconomically through the historic period.

31
32 12) Staff recommends the Company explain in Rebuttal Testimony how customers can
33 expect to see the benefit of the Company's coal purchasing strategy of making high
34 cost, diversity coal purchases, and consider whether any limits should be placed on
35 such procurements.

36
37 13) Staff recommends the Company explain in Rebuttal Testimony why there was no
38 replacement power cost [REDACTED]

1 [REDACTED], which
2 was an expensive month in the historical period.
3

4 14) Staff recommends the Company explain in Rebuttal Testimony why fossil generating
5 unit planned outages have increased on average so significantly.
6

7 15) Staff recommends the Company provide a side-by-side comparison of the net
8 renewable costs from the historic period and the projected period quantifying the
9 impact of the Company's Renewable RFP cost recovery request in the context of total
10 program costs and revenues in Rebuttal Testimony. The Company should itemize
11 costs and revenues related to renewable programs using the same metrics for both the
12 historical and projected periods, such that the projected amounts can be readily
13 compared to historical period amounts on a one-to-one basis.
14

15 III. PROJECT SCOPE

16 **Q. PLEASE DESCRIBE THE OVERALL SCOPE OF DISCOVERY IN THIS CASE.**

17 A. In total, 12 formal sets of data requests were submitted that asked approximately 260
18 questions, and additional informal requests were made to the Company. During this
19 proceeding, Staff had multiple conference calls with Company personnel and submitted
20 and reviewed responses to Staff discovery requests.

21 **Q. PLEASE DESCRIBE THE PURPOSE OF THE FUEL COST RECOVERY**
22 **(“FCR”) TARIFF.**

23 A. The purpose of the FCR tariff is to establish a fuel charge to collect revenues from
24 ratepayers for fuel costs projected to be incurred by the Company and for previously
25 uncollected fuel expenses as allowed.

26 **Q. WHAT AMOUNT HAS THE COMPANY DETERMINED IN ITS FILING THAT**
27 **WILL NEED TO BE RECOVERED THROUGH FCR-27 RATES?**

28 A. The Company's B2026 budget projection forecasts that the Company will need to recover

1 \$5.3 billion for future fuel costs incurred June 2026 through May 2028, including
2 carrying costs, through Part-A rates.⁴ The Company also anticipates collecting \$ [REDACTED]
3 million in under-recovered fuel costs, including carrying costs, remaining from the
4 historical FCR-27 period (June 2023 – May 2026) through Part-B rates. The Company
5 designed the FCR-27 Part-B rate to fully pay off the remaining under-recovered balance
6 over the three-year period of June 1, 2026 through May 31, 2029.⁵ The Company's
7 projection of \$ [REDACTED] million may be smaller than the actual balance by May 2026, and
8 Staff recommends the Company should recompute the Part-B rate at the time it files
9 rebuttal testimony.

10 **Q. WHAT COSTS ARE ELIGIBLE FOR RECOVERY IN THE FCR?**

11 A. Fuel costs that are eligible for recovery are defined in the Georgia statute, O.C.G.A. §
12 46-2-26 (a)(1), which states, "*Fuel costs*" of a utility company means the cost of fuel as
13 defined in the utility company's tariffs in effect on July 1, 1979, as such tariffs may be
14 changed from time to time by order of the commission as provided by law."
15 Consequently, fuel costs recoverable in the FCR balance are those costs listed in the
16 utility's most recent FCR tariff, which have been explicitly approved by the Commission.

17 **Q. HOW ARE RECOVERABLE FUEL COSTS DEFINED IN THE FCR TARIFF?**

18 A. Georgia Power's prior FCR-26 and its proposed FCR-27 Tariff define recoverable fuel
19 costs exactly the same as follows:⁶

20 Fuel Costs shall be the cost of:

⁴ MFRP-1 FCR-27 Budget TS.xlsx, Tab: FCR Part A.

⁵ MFRP-1 FCR-27 Budget TS.xls, Tab FCR Part B. In the Company's February 2026 FCR Monthly Over / Under Report Docket 3382 the uncollected balance as of May 2026 is estimated to be \$ [REDACTED] million.

⁶ Recoverable fuel costs defined in FCR-26 in Adams/Houston Direct Testimony Attachment A for FCR-26, Attachment B for TOU-FCR-6, and Attachment C for TOU-FCR-TP-4.

- (1) fossil, nuclear, bio-mass (including renewable) fuel and emission allowances (including credits, offsets, taxes, tariffs or other mechanisms intended to establish a market price for carbon, carbon dioxide and/or other greenhouse gases) consumed in the Company's own plants, and the Company's share of fossil, nuclear, and bio-mass (including renewable) fuel and emission allowances (including credits, offsets, taxes, tariffs or other mechanisms intended to establish a market price for carbon, carbon dioxide and/or other greenhouse gases) consumed in jointly owned or leased plants; plus
- (2) the identifiable fossil, nuclear, bio-mass (including renewable) fuel and emission allowance costs (including credits, offsets, taxes, tariffs or other mechanisms intended to establish a market price for carbon, carbon dioxide and/or other greenhouse gases) associated with energy purchased for reasons other than identified in (3) below; plus
- (3) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost of energy; less
- (4) the cost of fossil, nuclear, bio-mass (including renewable) fuel and emission allowances (including credits, offsets, taxes, tariffs or other mechanisms intended to establish a market price for carbon, carbon dioxide and/or other greenhouse gases) recovered through intersystem sales when sold on an economic dispatch basis; less
- (5) retail portion of gains resulting from the sale of any emissions allowances; less
- (6) seventy-five percent of net gains from wholesale market opportunity sales; plus or minus
- (7) net gains and losses incurred under the Natural Gas and Oil Procurement and Hedging Program implemented in Docket No. 16134-U; plus or minus
- (8) carrying costs on over or under recovered fuel balance calculated at the Company's short term debt rate and excluding the first \$15 million of any under recovered cost; plus or minus
- (9) other costs or credits as determined by the Commission for inclusion in, or reduction of, recoverable fuel costs.

The Company states it has not introduced any new cost categories in its FCR accounting since FCR-26.⁷ The Company also states it requests the Commission to continue authorizing "Georgia Power to recover all Renewable RFP (utility scale and distributed generation) and renewable subscription program-related costs not otherwise

⁷ STF-JKA-1-3.

recovered by the Company through Bid Fees and Winner's Fees through the fuel clause, consistent with past practice."⁸

Q. HAS STAFF DETERMINED IF THE COMPANY FULLY COMPLIED WITH THE COMMISSION'S ORDER IN FCR-26?

A. Yes, Staff reviewed the Commission's Order in FCR-26 that was filed May 25, 2023.

Some of the key items included:

- Authorization to create a Part-A rate to recover future fuel costs, and a Part-B rate to recover historical under-recovered fuel costs left over from the prior FCR period.
- A requirement to reduce the fuel balance by \$7 million.
- A requirement to modify the Interim Fuel Rider ("IFR") mechanism so that the maximum amount by which fuel rates could be adjusted during an FCR cycle would be 40% above or below the approved FCR-26 rates. The +/- \$200 million threshold approved in FCR-23 was continued, but the Commission only required it be applied to the Part-A fuel balance.
- A requirement to provide on June 30 and December 31 of each year, updated projected fuel balance information based on updated assumptions. The Company was only required to update its natural gas price forecast for the June report.
- A requirement to file the next FCR case by Feb. 28, 2026.

The only item from the prior case Staff is concerned about relates to the IFR mechanism. At present the Company is required to inform the Commission when the Part-A fuel balance exceeds the \$200 million threshold; however, the Company is permitted to decide whether to make a formal request to change Part-A fuel rates prior to the next FCR proceeding. Since FCR-26, the Company filed eight IFR notifications, but

⁸ Direct Testimony of Adam Houston and Matthew Berrigan on behalf of Georgia Power Company, p. 24, l. 21.

1 it did not seek an adjustment to the FCR Part-A rate on any of those occasions.⁹ Staff has
2 considered this practice and discusses it at greater length below.

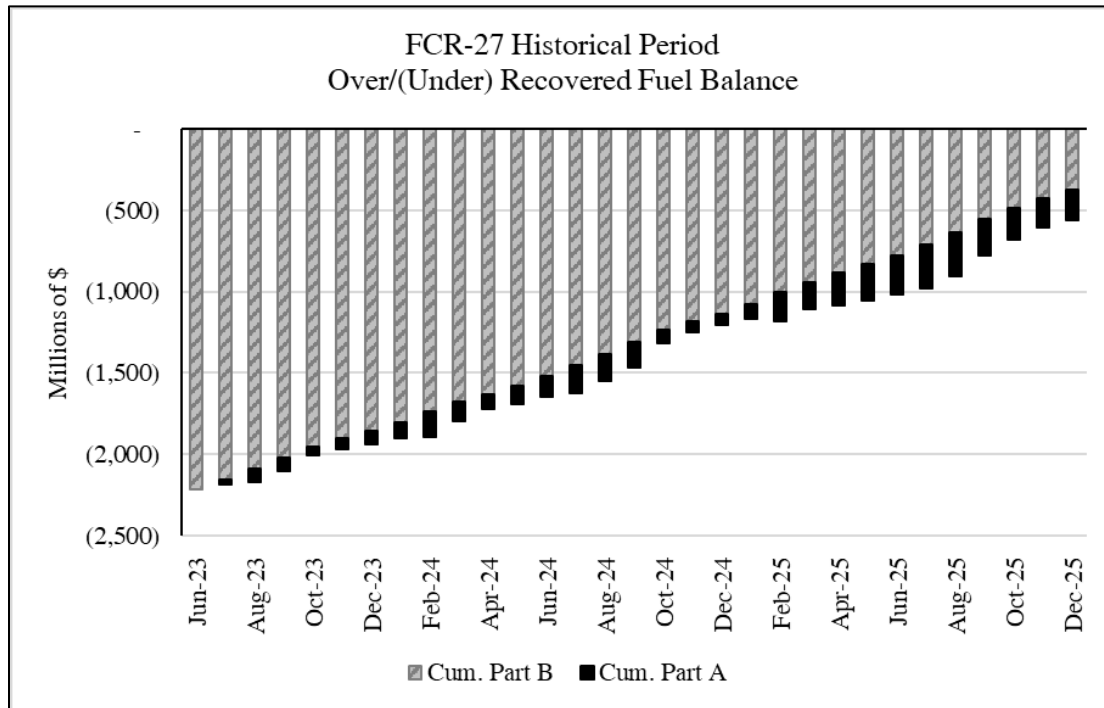
3 **Fuel Balance and Proposed Rates**

4 **Q. WHAT HAPPENED TO THE FUEL BALANCE DURING THE FCR-27**
5 **HISTORICAL PERIOD?**

6 A. The following figure shows the historical fuel balance, both Part-A and Part-B, beginning
7 June 2023 when FCR-26 rates first went into effect. Early in this period, the under-
8 recovered fuel balance exceeded \$2 billion, but declined steadily over the period, and by
9 December 2025, it decreased to approximately \$522 million.¹⁰ The remaining Part B
10 balance is projected to be paid off as of May 31, 2026.

⁹ Direct Testimony of Adam D. Houston and Matthew S. Berrigan on behalf of Georgia Power Company, p. 13.

¹⁰ The Direct Testimony of Adam D. Houston and Matthew S. Berrigan on behalf of Georgia Power Company, at p. 12, indicates the fuel balance consists of \$310 million of under-recovered fuel costs that existed at the start of FCR-26 (Part B), and \$212 million of under-recovered fuel costs that occurred since FCR-26 rates became effective (Part A).

Figure 1¹¹

Q. WHAT ARE THE FCR-27 RATES THAT THE COMPANY HAS PROPOSED IN THIS PROCEEDING?

A. The Company has proposed the following FCR-27 two-part rate to recover two years of projected fuel costs until the next fuel proceeding occurs (Part-A), and to recover the projected remaining under-recovered fuel balance from the FCR-27 historical period as of May 31, 2026 amortized and collected over a 3-year period (Part-B).¹² The overall costs are assigned to summer and winter periods and seasonal rates are derived as presented in the following table.

¹¹ "MFRH-14 TS.xlsx."

¹² STF-JKA-3-20.

Table 2: Non-Seasonal and Seasonal FCR-27 Rates ¹³

	Part A Projected Budget (2 year)	Part B Historic Under-Recovery (3 year)
Recoverable Costs (\$000)	\$5,278,751	\$ 296,777
Carrying Cost (\$000)	\$ (2,069)	\$11,845
Total Costs (\$000)	\$ 5,276,682	\$308,623
Applicable Sales (MWh)	143,524,387	217,702,481
Non-Seasonal Rate c/kWh	3.6765	0.1418
Summer Rate c/kWh	3.6450	.1423
Winter Rate c/kWh	3.6953	.1415

The projected rates are further stratified into summer and winter rates for Transmission, Primary, and Secondary customers.

Q. WHAT DOES TRANSMISSION, PRIMARY AND SECONDARY STRATIFICATION REPRESENT?

A. Stratification refers to the voltage level at which customers receive electric service. Large industrial customers are typically billed at FCR transmission rates as they take service at higher voltage levels. Residential customers are billed at FCR secondary rates as they take service at lower voltage levels. Rates are stratified to account for differences in expected lines losses that occur as power is distributed from generation plants to customers, with higher line losses occurring as power is distributed to the lowest voltage levels (residential customers). The Company's Direct Testimony includes Tables 1 and 2 showing the stratified, seasonal fuel rates.

Q. HOW DO THE COMPANY'S PROPOSED FCR-27 RATES COMPARE TO THE CURRENT FCR-26 RATES?

A. The Part A summer and winter projected rates have increased by approximately 6% and

¹³ MFRP-1 FCR-27 Budget TS.xls, tabs: "FCR 27 Part A" and "FCR 27 Part B."

18%, respectively, compared to the Part-A rates from FCR-26.¹⁴ However, overall, the Summer and Winter average FCR-27 rates are lower than the average FCR-26 rates by 17% and 10%, respectively, primarily due to the significant reduction in the FCR-26 Part-B under-recovered balance, as shown in table 3 below.

Table 3: FCR-26 vs. FCR-27 rates¹⁵

	FCR-26	FCR-27	% change
Summer			
Part A	3.4274	3.6450	6%
Part B	1.1259	0.1423	-87%
Total	4.5533	3.7873	-17%
Winter			
Part A	3.1380	3.6953	18%
Part B	1.1158	0.1415	-87%
Total	4.2538	3.8368	-10%

This is not surprising because by design the Part-B under-recovered balance from FCR-26 was to be completely paid off during the FCR-27 historical period. Georgia Power noted that, on average, there would be a decrease of approximately \$5.74 per month on the total bill (including base and other rate components) of a typical 1,000 kWh residential customer related to FCR fuel costs.¹⁶

Q. HOW ARE THE PROJECTED RATES EXPECTED TO CHANGE OVER TIME?

A. The Company's FCR-27 Part-A projected period rate is expected to recover 24 months of projected costs associated with the period of June 1, 2026 to May 31, 2028. The Company proposes that the 24-month rate will be in effect until the next FCR proceeding changes the projected Part-A rate, or until the IFR results in a change to the projected

¹⁴ FCR-27 Exhibits PD.xlsx, Tab: Exhibit 6.

¹⁵ FCR-27 Exhibits PD.xlsx, Tab: Exhibit 6.

¹⁶ Direct Testimony of Adam Houston and Matthew Berrigan on behalf of Georgia Power Company, p. 3.

Part-A rate.

The following table compares the Company's proposed average 24-month Part-A rate (summer and winter combined) to projected rates calculated over different time periods, as indicated in the table. The yearly rates are projected rates that correspond to specific 12-month time periods as indicated in the table, and the 36-month projected rate captures costs over the more extended period of June 1, 2026 to May 31, 2029. While the Company proposes a rate based on a 24-month projection, the Company is not proposing a specific date for its next fuel case.

Table 4: Average Non-Seasonal Part-A Rate (c/kWh)

	Proposed 24-Month Rate	Year 1 12-Month Rate	Year 2 12-Month Rate	Year 3 12-Month Rate	36-Month Rate
Start	Jun-26	Jun-26	Jun-27	Jun-28	Jun-26
End	May-28	May-27	May-28	May-29	May-29
c/kWh	3.6765				

The three individually forecasted rates increase year after year, because of escalating costs and increases in sales expected to require the acquisition of additional amounts of purchase power. In essence, the Company's 24-month proposed rate is the average of the first two years' rates. The advantage of holding the fuel rate constant over a two-year period is that it minimizes the number of rate changes that would occur, though in periods of volatility it could lead to customers being charged rates that are out of sync with actual fuel costs the Company incurs. Staff does not oppose the Company's proposed 24-month Part-A rate, particularly because the IFR could be used to address volatility in the event rates customers are charged become significantly different

1 compared to the actual fuel costs the Company incurs.¹⁷

2 **Time-of-Use FCR Rates**

3 **Q. HOW DID THE COMPANY DERIVE THE TIME-OF-USE RATES?**

4 A. In addition to the FCR-27 rate, the Company also proposed two time-of-use rates. The
5 following is described in the Company's tariffs:

6 **FCR-27:** This schedule is applicable to and becomes a part of each retail rate
7 schedule in which reference is made to the Fuel Cost Recovery Schedule unless
8 an account is billed on a Time of Use Fuel Cost Recovery Schedule.
9

10 **TOU-FCR-7:** Available to all customers in Georgia Power Company's service
11 area served on the Time of Use – Residential Energy Only (TOU-REO), Time of
12 Use – Overnight Advantage (TOU-OA), Time of Use – Residential Demand
13 (TOU-RD), Time of Use – Energy Only (TOU-EO), Time of Use – General
14 Service Demand (TOU-GSD), Time of Use – Food and Drink (TOU-FD), Time
15 of Use – Electric Vehicle Charging (TOU-EVC), Time of Use – High Load Factor
16 (TOU-HLF), Time of Use – Revenue Neutral (TOU-RN), Fixed Pricing
17 Alternative (FPA), Time of Use – Supplier Choice (TOU-SC), and Farm Service
18 (FS) retail rate schedules and any other tariff ordered by the Georgia Public
19 Service Commission
20

21 **TOU-FCR-TP-5** Available to all customers in Georgia Power Company's
22 service area served on the Time of Use – Food and Drink (TOU-FD) and the Time
23 of Use – Overnight Advantage (TOU-OA) retail rate schedules and any other
24 tariff ordered by the Georgia Public Service Commission.

25 **Q. WHAT FUEL TARRIFF WILL NEW LARGE LOAD CUSTOMERS RELY ON?**

26 A. The majority of the Company's new large load customers are served under Time of Use
27 – High Load Factor (TOU-HLF), Time of Use – Revenue Neutral (TOU-RN), Fixed
28 Pricing Alternative (FPA), Time of Use – Supplier Choice (TOU-SC) rates for a fixed

¹⁷ Based on the Company's proposed Part-A rate, and assuming the Company's fuel cost projection is accurate, and no fuel rate change were to occur, then an additional Part A under-recovery of approximately \$283 million will occur in the third year (June 2026 – May 2029).

portion of its bill, the customer baseline.¹⁸ New large load customers (after April 2025) will be served under the TOU-SC tariff with a customer specific Monthly Access Charge (“MAC”).

Q. HOW DO FCR-27 FUEL RATES COMPARE TO THE FCR-27 TIME-OF-USE FUEL RATES?

A. The following table provides a comparison of the three rates, FCR-27, TOU-FCR-7, and TOU-FCR-TP-5.

Table 5: TOU FCR Rates (Secondary)
\$/kWh

	FCR-27	TOU-FCR-7 ¹⁹	TOU-FCR-TP-5 ²⁰
Non-Seasonal	.038471		
On-peak		.052397	.052397
Off-peak		.037533	.038785
Super Off Peak			.034832

The Company describes the derivation of the TOU rates as being revenue neutral, indicating, “The peak and off-peak period rates used in the Time-of-Use (“TOU”) fuel tariffs are derived by applying a ratio to the proposed non-seasonal FCR-27 prices by

¹⁸ “The CBL represents a customer’s normal operation for billing under its conventional tariff. The CBL is initially developed using either customer-specific hourly firm load data or monthly billing determinant data that represents the electricity consumption pattern and level agreed to by the customer and Georgia Power. Changes in consumption, measured from the CBL, are billed at RTP-HA prices. The CBL is the basis for achieving revenue neutrality with the appropriate non-RTP-HA firm load tariff on a customer specific basis. Mutual agreement on the CBL is a precondition for use of RTP-HA.” Tariff RTP-HA-12

¹⁹ The On-Peak period is defined as the hours starting at 2:00 p.m. and ending at 7:00 p.m. Monday through Friday for the calendar months of June through September (Summer Months). The Off-Peak period is defined as all hours not included above in the On-Peak period including all weekends and the calendar months of October through May (Winter Months).

²⁰ The On-Peak period is defined as the hours starting at 2:00 p.m. and ending at 7:00 p.m. Monday through Friday for the calendar months of June through September (Summer Months). The Off-Peak period is defined as the hours between 7:00 a.m. and ending at 11:00 p.m. for weekends, holidays, and the calendar months of October through May. The Off-Peak period for the calendar months of June through September (Summer Months) is defined as the hours between 7:00 a.m. and 2:00 p.m. and the hours between 7:00 p.m. and 11:00 p.m. Monday through Friday. The Super Off-Peak period is defined as the hours between 11:00 p.m. and 7:00 a.m. Monday through Sunday for all calendar months.

service level. Those ratios are calculated using the weighted marginal cost of energy (i.e., lambda) by TOU period over the projected test period.”²¹

IV. HISTORICAL REVIEW - VARIANCE ANALYSIS

Historical Variance Analysis

Q. HAVE YOU COMPARED BUDGETED SALES AND FUEL REVENUES TO ACTUAL SALES AND FUEL REVENUES DURING THE HISTORICAL PERIOD?

A. Yes, Staff compared budgeted sales and revenues projected in the last FCR proceeding (FCR-26) to the actual sales and revenues that occurred.²² This comparison covered the 36-month historical period for FCR-26 of January 2023 through December 2025, or calendar years 2023, 2024, and 2025. The following tables summarize the differences between actual and projected sales and revenue.

Table 6: Historic Variance Analysis - Sales²³

January 2023 – December 2025	Sales Revenue (\$M)			Sales Energy (GWh)			Sales (\$/MWh)		
	Actual	Proj.	Var.	Actual	Proj.	Var.	Actual	Proj.	Var.
Retail Sales	9,728	9,982	(254)	260,818	259,376	1,442	\$37.3	\$38.5	(\$1.2)
Wholesale Sales	512	310	202	16,895	6,233	10,662	\$30.3	\$49.8	(\$19.4)
Other ²⁴				10,732	10,842	(111)			
Total	10,240	10,292	(52)	288,864	276,452	11,993	\$36.9	\$38.7	(\$1.9)

The most significant observations are that actual retail energy requirements were higher than the projection by a small amount, while wholesale load was almost three times the

²¹ STF-JKA-3-13.

²² Actual costs and projected costs were obtained from “MFRH-2 TS.xlsx” Tab: Cumulative.

²³ Actual costs and projected costs were obtained from “MFRH-2 TS.xlsx” Tab: Cumulative.

²⁴ Includes GPC Use, Losses, and Unbilled Sales. Unbilled revenues and unbilled energy sold are reported on FERC Form 1 page 304 and represents energy usage and service revenue earned but not yet billed as of the end of a reporting period. Generally, revenues are accrued for the unbilled energy usage by utilities and the amounts are reversed when billed.

projected amount. Also, the actual average revenue rate (\$/MWh) was a little below the projection for the period.

Q. WHAT ARE THE DRIVERS OF THE DIFFERENCES IN ACTUAL VERSUS PROJECTED RETAIL SALES?

A. The following table compares the actual versus projected retail sales during the historic period and shows the components that make up retail sales.

**Table 7: Historic Billed Retail Sales
January 2023 – December 2025 ²⁵**

	Actual Total MWHs	Projected Total MWHs	Variance Total MWHs	Variance %
Residential	86,467,038	87,655,742	(1,188,704)	-1.4%
Commercial	101,865,907	97,137,811	4,728,096	4.9%
Industrial	71,241,399	73,296,049	(2,054,650)	-2.8%
Street Lights	783,695	869,918	(86,223)	-9.9%
MARTA	459,892	416,863	43,029	10.3%
Total Retail Billed Sales	260,817,931	259,376,383	1,441,548	0.6%

Residential, Industrial and Street Light sales were lower than projected, and Commercial sales were higher due to an increase driven by Georgia's robust business growth.²⁶ There was also an increase in Railway Service associated with MARTA.

Q. HAVE YOU COMPARED PROJECTED GENERATION COSTS AND ENERGY TO ACTUAL GENERATION COSTS AND ENERGY DURING THE HISTORICAL PERIOD?

A. Yes. The following table compares the projection that covered the FCR-27 historical period (2023 to 2025 calendar year period) to the actual costs and generation that occurred during that period.

²⁵ MFRH-13.5 TS.xlsx Tab: "Historic Period Variance."

²⁶ MFRH-13.5 TS.xlsx Tab: "Historic Period Variance."

1 **Table 8: Historic Variance Analysis - Generation** ²⁷

January 2023- December 2025	Generation Cost (\$M)			Generation Energy (GWh)			Generation (\$/MWh)		
	Actual	Proj.	Var	Actual	Proj.	Var	Actual	Proj.	Var
Natural Gas	2,460	2,712	(252)	86,066	87,695	(1,630)	\$28.6	\$30.9	(\$2.3)
Coal Steam	1,875	817	1,057	38,070	15,778	22,292	\$49.2	\$51.8	(\$2.5)
Nuclear	575	631	(55)	65,461	68,349	(2,888)	\$8.8	\$9.2	(\$0.4)
Purchase Power	2,158	2,663	(505)	67,218	69,086	(1,869)	\$32.1	\$38.5	(\$6.4)
Hydro	-	-	-	3,885	4,012	(128)	\$0.0	\$0.0	\$0.0
Solar (Purchased)	615	761	(146)	17,488	20,283	(2,796)	\$35.1	\$37.5	(\$2.4)
Solar (Owned)				1,834	1,995	(161)			
Biomass	514	581	(67)	6,718	7,680	(962)	\$76.5	\$75.6	\$0.9
Wind	145	108	36	2,145	1,606	539	\$67.4	\$67.3	\$0.1
BESS	(1)	-	(1)	(19)	(33)	13	\$37.5	\$0.0	\$37.5
Total Fuel Expense	8,341	8,273	67	288,864	276,452	12,412	\$29.8	\$30.5	(\$0.7)
Hedging	274	156	118						
Miscellaneous ²⁸	92	132	(41)						
Recoverable Costs	8,706	8,562	144	288,864	276,452	12,412	\$30.1	\$31.0	(\$0.8)

2 Key variances include a significant increase in coal generation and costs, a
3 decrease in natural gas, nuclear, purchase power, solar and biomass generation, and an
4 increase in the amount of wind generation between the projected and actual results.
5 Actual purchase power energy was lower than the projection by only 3%; however, the
6 total cost associated purchase power was significantly less than projected by
7 approximately 19%. Generally, the average rate (\$/MWh) for purchase power trended
8 below the projection in 2023 and 2024, and was close to the projection through 2025,
9 following high costs in January 2025. Because of an increase in sales, Net Generation
10 increased compared to the projection; however, despite the increase in Net Generation,
11 the overall Generation Cost increased by less than 2%.

²⁷ Actual costs and projected costs were obtained from "MFRH-2 TS.xlsx" Tab: Cumulative.

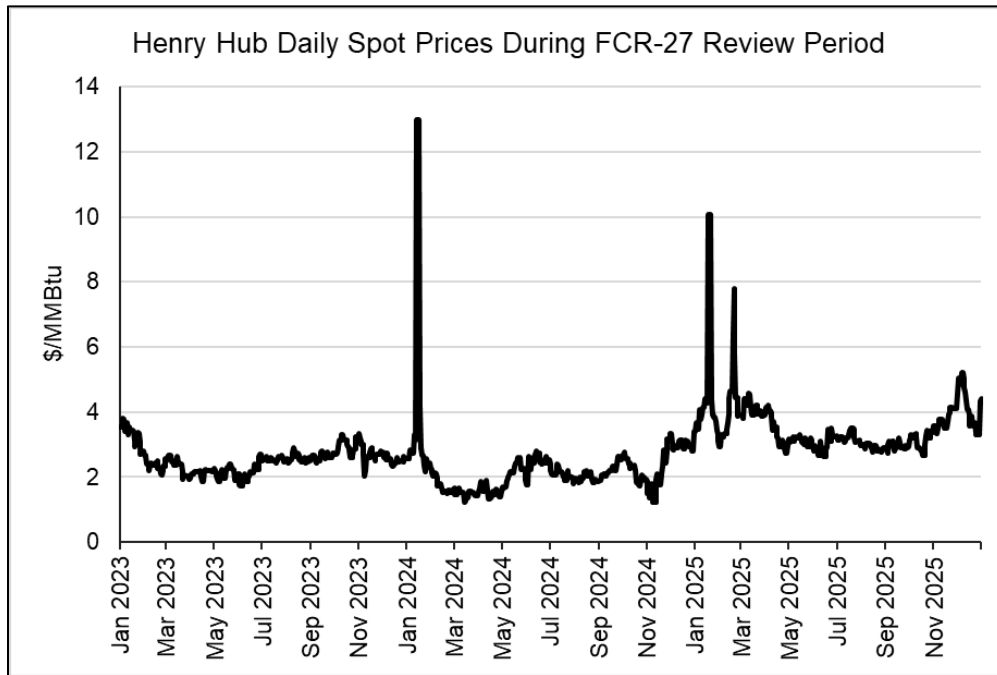
²⁸ Miscellaneous Category includes: Emission Allowances – SO₂, Emission Allowances – NO_x, Economy Energy Profits, Carrying Cost/(Benefit), Net Renewable Program Expenses/(Revenues), EPA Auction Proceeds, Spent Nuclear Fuel Litigation Awards, FCR-26 Settlement Adjustment, Excess ADIT Adjustment: State Income tax rate change - Part A, Excess ADIT Adjustment: State Income tax rate change - Part B.

1 **Q. HOW DID THE COMPANY'S HENRY HUB NATURAL GAS PRICE**
2 **PROJECTION COMPARE TO ACTUAL RESULTS?**

3 A. The Company included a comparison of monthly average projected versus actual Henry
4 Hub prices covering the FCR-27 historical period in Chart 1 in Company Witnesses
5 Houston and Berrigan's Direct Testimony. The chart indicates that other than in the
6 January 2024 and January 2025 months, the actual Henry Hub prices were less than the
7 projected prices. In the two January months the actual and projected prices were nearly
8 identical.

9 **Q. HOW DID VOLATILITY IN NATURAL GAS PRICES AFFECT THE**
10 **OVERALL COSTS CUSTOMERS HAD TO PAY FOR NATURAL GAS?**

11 A. The following chart depicts the daily volatility of the Henry Hub Natural Gas Price in the
12 historical period.

Figure 2: Daily Natural Gas Spot Pricing²⁹

The chart shows that three significant spikes occurred during the review period, Winter Storm Heather in January 2024, Winter Storm Cora in January 2025, and Winter Storm Enzo in February 2025. However, the spikes were short lived, and Chart 1 from Company Witnesses Houston and Berrigan's Direct Testimony indicates the spikes did not cause significant increases in costs over a long period.

Historical Generation Mix

Q. HOW DID GEORGIA POWER'S ACTUAL MIX OF GENERATION CHANGE OVER TIME?

A. The following table compares the sources of generation and costs for the resources that were used to supply the actual load during the FCR-27 historical period (2023-2025) year over year.

²⁹ STF-JKA-2-1. See also Georgia Power Direct Testimony, Chart 3

1 **Table 9: Historic Annual Cost and Generation Mix³⁰**

	Generation Cost (\$M)			% Generation Cost			% Generation Energy		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Natural Gas							33.1%	30.1%	26.5%
Coal Steam							12.8%	13.0%	13.7%
Nuclear							20.3%	23.9%	23.6%
Purchased Power							23.9%	21.7%	24.2%
Hydro							1.4%	1.3%	1.4%
Solar							5.2%	6.9%	7.8%
Biomass							2.5%	2.4%	2.1%
Wind							0.8%	0.7%	0.7%
BESS							0.0%	0.0%	0.0%
Hedging							0.0%	0.0%	0.0%
Miscellaneous ³¹							0.0%	0.0%	0.0%
Total	\$2,850	\$2,715	\$3,142	100%	100%	100%	100.0%	100.0%	100.0%

2 Comparing total generation cost, there was a slight decrease of about 5% between 2023
3 and 2024 and an increase of 15% from 2024 to 2025 in costs to meet customer
4 requirements. The results show a continued reliance on natural gas, coal, nuclear, and
5 purchased power, with some additional growth in renewables such as solar. Additionally,
6 there was a slight jump in nuclear generation between 2023 and 2025, reflecting the new
7 Vogtle 3 and 4 nuclear units.

8 **Renewable Energy Programs**

9
10 **Q. ARE THE COSTS AND REVENUE OF RENEWABLE ENERGY PROGRAMS**
11 **INCLUDED IN FCR RATES?**

³⁰ Actual and projected costs were obtained from "MFRH-2 TS.xlsx."

³¹ Miscellaneous includes Emission Allowances – SO₂, Emission Allowances – NO_x, Economy Energy Profits, Carrying Cost/(Benefit), Net Renewable Program Expenses/(Revenues), EPA Auction Proceeds, Spent Nuclear Fuel Litigation Awards, FCR-27 Settlement Adjustment, Excess ADIT Adjustment: State Income tax rate change - Part A, Excess ADIT Adjustment: State Income tax rate change - Part B.

A. Yes. Revenues from participating customers in the Company's Green Energy riders are used to offset program costs first and then are used to offset the cost of purchasing renewable energy included in the FCR. These programs include the Company's Advanced Solar Initiative ("ASI"), Renewable Energy Development Initiative ("REDI"), Simple Solar, Green Energy Program, RNR, and Solar Purchase ("SP") programs, as well as Qualifying Facilities ("QF") purchases. The types of purchased energy sources in these programs include solar, biomass, hydro, landfill gas, wind, fuel cells, and mixed types of renewable energy. Staff conducted a high-level review of these green energy programs, including reviewing MFRH information, and information provided in data responses.

**Table 10: Summary of Renewable Program
Labor and Expenses ³²**

Components	2023-2025
Labor (GPC)	
Materials & Fuel (GPC)	
Software Expenses (GPC)	
Other Expenses (GPC)	
IE Costs	
3rd Party Costs	
Total Labor and Expense Costs ³³	

The Company also identified approximately \$49.3 million in revenues (which includes Bid Fees, Winners Fees, Bid Securities, Assignment Fees, Liquidated Damages, Witness test Re-testing, and Interconnection Study Fees) and \$27.9 million in RFP related expenses over the historic period (January 2023-December 2025).³⁴ Specifically, the Company estimated historic RNR administrative costs at \$6.9 million and CARES

³² STF-PIA-5-1. The net renewable program costs for the historic period total to approximately \$ [REDACTED].

³³ Excludes REC procurement costs, transmission, additional sum, and renewable integration costs.

³⁴ STF-JKA-2-29.

1 Program expenses at \$8.2 million, inclusive of Bid Fees, Bid Securities, Winner Fees,
2 Assignment Fees, and Liquidated Damages.³⁵

3 **Coal Review**

4 **Q. DOES THE COMPANY HAVE A REQUIREMENT TO MEET SPECIFIC COAL**
5 **INVENTORY TARGETS?**

6 A. Yes. In FCR-22, the Commission approved the Company's request to widen the
7 inventory target range from 45 to 50 days of inventory to 40 to 50 days of inventory at
8 each of its coal-fired power plants.³⁶ The target has not changed since FCR-22.³⁷

9 **Q. DID THE COMPANY MEET THESE TARGETS IN THE FCR-27 HISTORICAL**
10 **PERIOD?**

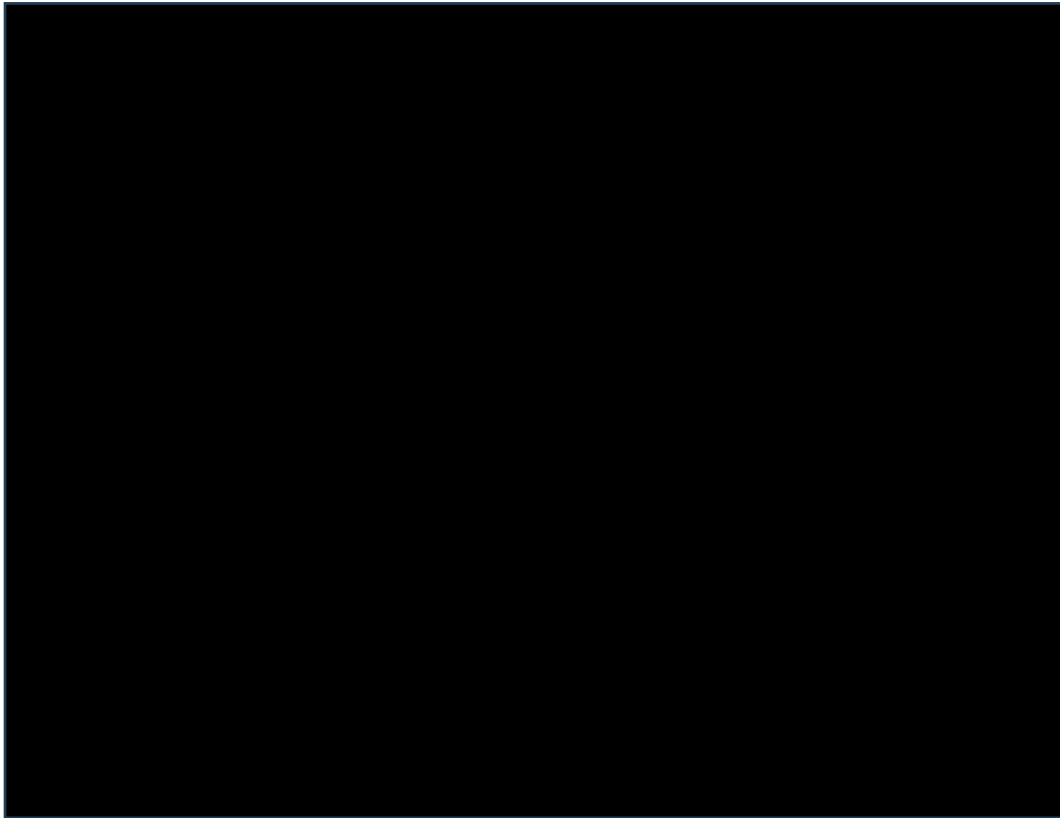
11 A. The following figure compares the Company's Target versus Actual Inventory Levels
12 during the FCR-27 historical period for both Plant Scherer and Bowen.

³⁵ STF-JKA-2-30.

³⁶ Final Order 33302 filed in Docket No. 28945 (FCR-22).

³⁷ MFRH-3.1 TS.xlsx, tab: "Coal Inventory Targets."

Figure 3: Coal Inventory³⁸



██████████ began the review period ██████████ minimum inventory target level, but then both plants ██████████ the minimum inventory target level for most but not all of the FCR-27 historical review period. ██████████

³⁸ Inventory targets: MFRH-3.1 TS.xlsx and actual inventory values from MFRH-3.2 Coal TS.xlsx.

1 **Q. HAS THE COMPANY UPDATED ITS METHODOLOGY TO COAL**
2 **INVENTORY MANAGEMENT?**

3 A. The Company noted it continues to engage in real time management of its coal
4 inventories; however, it also stated that it began formal monthly reviews of forecasted
5 coal plant operation and expected coal deliveries in 2023.³⁹

6 **Q. WERE ANY COAL UNITS OPERATED UNECONOMICALLY AT ANY TIME**
7 **DURING THE FCR-27 HISTORICAL PERIOD?**

8 A. It is not clear. Staff asked the Company in discovery request STF-JKA-1-29 and STF-
9 JKA-3-30 whether any coal units were dispatched uneconomically during the FCR
10 historical period to manage coal inventories. The Company's answers did not appear to
11 be responsive. Presumably, the determination of whether a generating unit was
12 uneconomically dispatched for a given time period could be determined from daily
13 generating unit dispatch operating logs. The Company's standard operating procedure is
14 to commit and dispatch the lowest cost generation available, subject to identifiable
15 constraints. The Company should be aware of any constraints that resulted in
16 commitment and dispatch out of economic order. However, the Company claimed that it
17 could not determine whether a specific unit was committed and dispatched
18 uneconomically because of its new coal inventory management process. In MFRH-3.1,
19 the Company described various considerations for coal dispatch to manage reliability,
20 production costs, coal supply availability, and coal inventories. The Company stated:

³⁹ Georgia Power response to STF-JKA-3-29.

1 Because coal management is now addressed on a monthly basis, and
2 because of unit constraints, the Company cannot determine whether a
3 specific unit was run due to coal inventory management or due to specific
4 operating constraints.⁴⁰

5
6 It is unclear why managing coal inventory on a monthly basis means the Company could
7 no longer use daily operation logs to identify whether its coal units were operated
8 uneconomically.

9 The period between [REDACTED] was particularly conspicuous in that
10 inventory levels for both Plant Bowen and Scherer were [REDACTED] the maximum target
11 inventory level. Plant Scherer, especially, reached a point where its coal inventory was
12 [REDACTED] target inventory level. It is possible that to [REDACTED]
13 [REDACTED], the Company had to [REDACTED], yet the Company gave
14 no indication of whether that was the case in response to STF-JKA-3-29. The Company
15 was even asked in STF-JKA-4-17e for communication between [REDACTED] and the
16 dispatch center regarding uneconomic operation of the plant, but limited information was
17 provided. Staff has pursued this issue further and requested additional discovery;
18 however, those responses were not available at the time this testimony had to be
19 submitted.⁴¹

20 Staff recommends the Company definitively address this issue in Rebuttal
21 testimony and provide sufficient evidence to prove that the coal units were not operated
22 uneconomically.

23 **Q. PLEASE DISCUSS YOUR INVESTIGATION OF THE COMPANY'S COAL**
24 **PROCUREMENT ACTIVITIES IN THIS FCR.**

⁴⁰ MFRH-3.1

⁴¹ STF-JKA-7-1 and STF-JKA-7-4 (pending).

A. Staff investigated the Company's coal procurement practices following the same approach as in prior FCR proceedings, which included reviewing the Company's Buy Books, reviewing MFRs (3, 6, 7, 8 and 9), and requesting additional discovery.

Q. WHAT INFORMATION IS CONTAINED IN THE BUY BOOKS?

A. The Buy Books contain documentation concerning the procurement of coal typically based on the plants served by specific railroads, such as Norfolk Southern ("NS") or CSX. Typically, each Buy Book includes the following information:

- Reason for procuring coal
- Bid solicitation documentation
- Bids received and analysis of the bids
- Copies of communication with suppliers
- Email confirmation and letter confirmation of purchase agreements
- Contract documentation
- Analyses
- Purchase orders

Q. DID STAFF IDENTIFY ANY CONCERNS IN ITS REVIEW OF THE COAL BUY BOOKS?

A. Yes. During Staff's review, a couple of issues were identified and additional discovery was issued. One issue related to purchases of coal from the [REDACTED]. The price of coal from the [REDACTED] was significantly higher than other coal that was readily available, including from suppliers such as [REDACTED]. The Company signed contracts for less expensive coal from those suppliers and could have taken more coal from those suppliers but instead contracted with [REDACTED] at a [REDACTED] higher cost.

Q. WHAT PURCHASES DID THE COMPANY MAKE FROM THE [REDACTED]

MINE AT HIGHER COSTS?

A. Georgia Power first committed to a purchase from [REDACTED] based on a Long-Term (“LT”) solicitation issued [REDACTED]. The Company noted in the [REDACTED] that it had acquired [REDACTED], [REDACTED], [REDACTED].⁴² Additional coal was available from [REDACTED], and their Confirmation Agreements indicated that the coal was available at purchase prices that ranged from [REDACTED]. The Company also noted in the [REDACTED] that there were uncertainties associated with the [REDACTED]. [REDACTED].⁴³

Q. WERE ANY OTHER PURCHASES MADE FROM [REDACTED]?

A. Yes. Georgia Power committed to another purchase from [REDACTED] based on an [REDACTED] issued [REDACTED]. In a [REDACTED] dated [REDACTED], the Company committed to an additional [REDACTED] tons in [REDACTED] and [REDACTED] tons in [REDACTED] at costs of \$[REDACTED]/ton and \$[REDACTED]/ton, respectively.⁴⁴ The Company made these purchases despite noting in an internal Company email that other coal was available at cheaper prices, and in fact stated, “[REDACTED].”⁴⁵ The other coal offers ranged in price between \$[REDACTED] \$

⁴² This price was later determined to be \$[REDACTED]/ton refer to TAB 1 Documentation [REDACTED].

⁴³ TAB 4 [REDACTED] Confirmation [REDACTED] fully executed.pdf.

⁴⁴ The price was later determined to be \$[REDACTED] per the Company’s “Tab 6 [REDACTED].”

⁴⁵ TAB 4 Re_Bowen LT ([REDACTED]) purchase recommendations.

1 [REDACTED]. In the documentation, the Company continued to note [REDACTED]
2 [REDACTED].⁴⁶

3 **Q. WERE ANY OTHER SOLICITATIONS CONDUCTED THAT RESULTED IN**
4 **PURCHASES FROM THE [REDACTED]?**

5 A. Yes. A [REDACTED] LT solicitation was issued on [REDACTED]
6 [REDACTED] than other coal that was available at the time. In
7 addition, a further amount of coal was acquired from [REDACTED], which again increased
8 the [REDACTED] purchase amount based on [REDACTED]
9 to Georgia Power in [REDACTED]. The price offered was fairly high compared to
10 offers from other suppliers with coal available, whose prices ranged from [REDACTED]
11 [REDACTED]. The following table breaks down the timeline of all
12 [REDACTED] purchases and prices since 2024.

13 **Table 11: Timeline for Acquisition of [REDACTED] Tons**

			ktons				\$/ton			
Bid Issued	Confirmation Agreement Date	Type of Purchase	2026	2027	2028	2029	2026	2027	2028	2029

14 **Q. HOW DID THE COMPANY JUSTIFY MAKING SUCH EXPENSIVE COAL**
15 **PURCHASES?**

16 A. The Company explained that maintaining diversity with its suppliers and regions is

⁴⁶ Confirmation Agreement, TAB 4 [REDACTED] full executed GA Power [REDACTED].pdf.

⁴⁷ Email; [REDACTED] requested to add [REDACTED] for [REDACTED].

1 important. In the [REDACTED] dated [REDACTED], the Company
2 stated, “[REDACTED]
3 [REDACTED]
4 [REDACTED].” The Company also referred Staff to its Coal Procurement
5 Strategy Document as additional support,⁴⁸ which explained:

- 6 • [REDACTED]
7 [REDACTED]
8 [REDACTED]⁴⁹
9 [REDACTED]
10 [REDACTED]⁵⁰
- 11 • [REDACTED]
12 [REDACTED]
13 [REDACTED]⁵¹

14 **Q. DOES STAFF HAVE ANY CONCERNS ABOUT THE COMPANY’S**
15 **DECISIONS TO PURCHASE FROM THE BLACKHAWK MINE?**

16 A. Yes. While Staff acknowledges that the Company would like to maintain diversity with
17 its suppliers and regions from which it acquires coal, Staff is concerned that the added
18 cost of acquiring coal from the [REDACTED] mine is not inconsequential. A rough estimate
19 of the [REDACTED] coal acquisition as a percentage of total Bowen coal expected to be
20 purchased in 2027 is that [REDACTED] represents close to [REDACTED]% of the total coal
21 acquisition in 2027 [REDACTED]
22 [REDACTED]⁵²

23 **Q. WHERE ANY OTHER HIGH-COST [REDACTED] ENTERED**

⁴⁸ STF-JKA 4-18.

⁴⁹ MRFH-6 Attachment C TS.docx, p. 5.

⁵⁰ MRFH-6 Attachment C TS.docx, p. 5.

⁵¹ STF-JKA-4-18.

⁵² MFRP-7.1.

1 **INTO?**

2 A. Yes. The Company entered into other high-cost coal purchases as indicated in the
3 following table. The Company explained it entered into these Agreements for [REDACTED]
4 [REDACTED].⁵³

5 **Table 12: Other High-Cost [REDACTED] Coal Purchases**

		ktons					\$/ton				
Supplier ⁵⁴	Confirmation & Agreement Dates	2025	2026	2027	2028	2029	2025	2026	2027	2028	2029
Total											

6 Staff understands the Company's desire to acquire coal based on these reasons,
7 but this approach appears to be [REDACTED]. It would be understandable if
8 the Company did not have [REDACTED], but it appears it does.
9 Staff requests that in its rebuttal testimony, Georgia Power explain further how customers
10 can expect to see the benefit of the Company's coal purchasing strategy.

11 **Q. DID STAFF IDENTIFY ANY OTHER COAL ACQUISITION OR COAL**
12 **TRANSPORTATION ISSUES AS PART OF ITS INVESTIGATION IN THIS**
13 **PROCEEDING?**

14 A. Staff identified two other issues, including an ongoing coal transportation litigation
15 matter, and a coal supplier force majeure matter that arose during the historical period.

⁵³ Tab 1 Documentation 2026-2030 LT Purchase and Q1-Q2 spot.docx.

⁵⁴ [REDACTED]
[REDACTED]
⁵⁵ [REDACTED]

1 The coal transportation litigation matter is part of a long-running rail freight fuel
2 surcharge antitrust litigation case that Southern Company and many other coal shippers
3 filed against the four major U.S. freight railroads in the U.S. The case was filed in
4 October 2019 and accuses the freight companies of having conspired to fix prices for
5 freight rail transportation.⁵⁶ A decision was reached by a federal judge in 2025 at the U.S.
6 District Court for the District of Columbia in favor of the railroads; however, that
7 decision is now under appeal.⁵⁷

8 The coal supplier force majeure issue related to a [REDACTED]
9 [REDACTED],⁵⁸ which required
10 [REDACTED]
11 [REDACTED]
12 [REDACTED]. The Company did not provide any additional
13 information, likely because this is a very recent event. Staff will continue to monitor this
14 event.

15 Natural Gas Storage and Purchases Review

16 **Q. DOES THE COMPANY UTILIZE FIRM NATURAL GAS STORAGE?**

17 **A.** Yes. The Company utilizes firm natural gas storage capacity to:⁵⁹

18 [REDACTED]
19 [REDACTED]
20 [REDACTED]
21 [REDACTED]
22 [REDACTED]
23 [REDACTED]
24 2. [REDACTED]

⁵⁶ MFRH-8.

⁵⁷ <https://www.pymnts.com/cpi-posts/antitrust-case-against-freight-rail-giants-moves-to-appeals-court-after-dismissal/>

⁵⁸ The exact day was not specified.

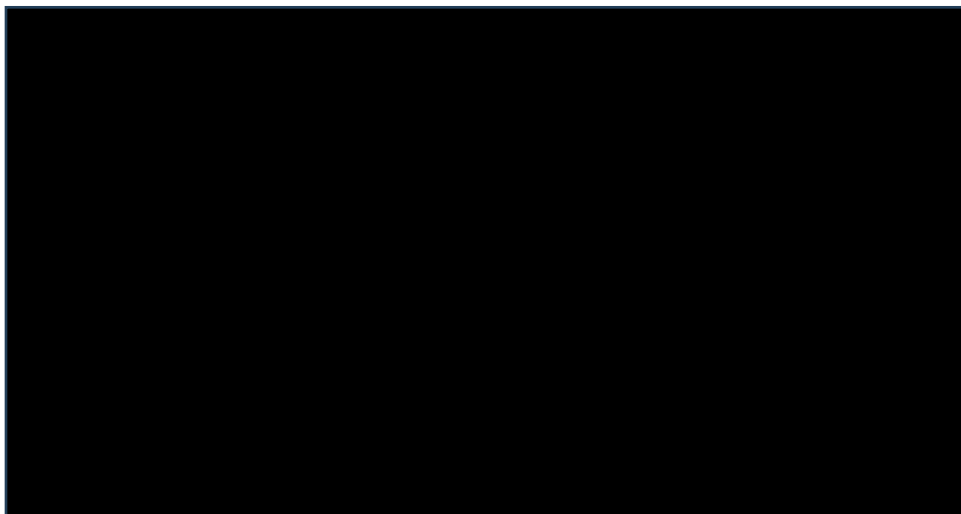
⁵⁹ MFRH-3.1 TS and MFRH Gas 3.2 TS.

1 [REDACTED]
2 [REDACTED]
3 [REDACTED]
4 The Company develops storage targets to meet the stated goals of the program.

5 **Q. DID THE COMPANY MEET THESE TARGETS IN THE HISTORICAL**
6 **PERIOD OF FCR-27?**

7 A. The Company's targeted storage level fluctuates with the seasons as seen in the figure
8 below. The Company met its firm natural gas storage targets for almost all months in the
9 review period. There were [REDACTED] in which the natural gas storage was slightly
10 less than the targeted amount and there were no more than [REDACTED] consecutive months
11 in which the storage fell below the target level during the historical period. Since the
12 Company mostly maintained storage levels above the targeted amount, presumably that
13 allowed the Company to meet its reliability objectives by avoiding natural gas disruptions
14 and maintaining operational balancing requirements.

15 **Figure 4: Natural Gas Storage Inventory⁶⁰**
16



17
18 **Q. IN ADDITION TO THE REVIEW OF THE NATURAL GAS STORAGE**

⁶⁰ Target values from MFRH-3.1 TS.xlsx and Ending Balance values from MFRH-3.2 Gas TS.xlsx.

**AMOUNTS DID STAFF REVIEW THE COMPANY'S NATURAL GAS
PURCHASES FOR THE HISTORIC PERIOD.**

A. Yes. Staff reviewed a sample of natural gas commodity spot purchases made during the historic period compared to monthly NYMEX pricing, daily Henry Hub pricing and transaction level adders for the purchases. Staff did not identify any concerns with the natural gas storage or purchases during the historic period.

Generator Outages

Q. DID STAFF REVIEW THE GEORGIA POWER'S FOSSIL PLANT OUTAGES?

A. Yes, this panel reviewed fossil unit outages and RTI Consulting reviewed nuclear unit outages. This panel examined unit outage information provided with the Company's filing in MFRH 4.2, which includes outage dates and durations, lost energy, NERC cause codes and a brief description of each outage event. The Company also included a table of unplanned fossil unit outages and derations that lasted longer than 7 days. This panel also reviewed select Root Cause Analyses ("RCAs")⁶¹ developed by the Company, which provided a more thorough explanation of the outages based on information the Company gathered from the personnel directly involved in the outages. The RCAs included a determination of the cause(s) of the outages, and a description of the actions that were taken to bring the plant back online.

Q. WHAT DID YOUR INITIAL REVIEW ENTAIL?

A. Staff's initial review focused on outages that resulted in a significant loss of energy, outages that lasted more than 7 days, and outages that resulted from errors, including

⁶¹ In addition to Root Cause Analysis, the Company used different names for some outage reports, including Corrective Action Report, Apparent Cause Analysis, and Event Learning Report.

operator, maintenance personnel, contractor, operating procedure, maintenance procedure, contractor procedure, and staff procedural errors, which were designated using the NERC Generating Availability Data System (“GADS”) cause codes 9900, 9910, 9920, 9930, 9940, 9950, and 9960 respectively.

Q. WHAT OUTAGES DID STAFF EXAMINE MORE CLOSELY?

A. Staff focused close attention on outages with units McDonough 5B, McDonough 6B, McIntosh CT7, and a series of outages caused by either contractor or operator errors.

Q. PLEASE DISCUSS THE [REDACTED] OUTAGE THAT OCCURRED [REDACTED] TO [REDACTED].

A. On [REDACTED] the [REDACTED] unit experienced an outage due to the [REDACTED]

The Company coded the outage using a NERC GADS cause code as [REDACTED]. However, Staff sought clarification of whether the outage was actually an [REDACTED] and the Company responded that the outage was [REDACTED]

[REDACTED]⁶² This outage spanned [REDACTED] hours and resulted in a replacement power cost of \$[REDACTED].

Q. WHAT IS STAFF’S RECOMMENDATION FOR THIS OUTAGE?

A. Staff recommends the fuel balance be reduced by \$[REDACTED] for the fuel replacement cost associated with this [REDACTED] outage considering that it was [REDACTED]

⁶² STF-JKA-4-24.

1 [REDACTED] as the Root Cause Analysis (“RCA”) stated.⁶³

2 **Q. PLEASE DISCUSS THE [REDACTED] OUTAGE THAT OCCURRED**
3 **BETWEEN [REDACTED].**

4 A. On [REDACTED], the [REDACTED] Unit experienced an outage due to a
5 Georgia Power [REDACTED]

6 [REDACTED]
7 [REDACTED].⁶⁴ Staff requested clarification in discovery as to why the Company
8 coded the outage an [REDACTED] rather than [REDACTED] and the Company
9 responded that the [REDACTED], was the party responsible [REDACTED].⁶⁵

10 This outage should have been [REDACTED]
11 [REDACTED]. Even though [REDACTED], the RCA stated that [REDACTED]

12 [REDACTED]
13 [REDACTED].⁶⁶ Again, even though [REDACTED]
14 [REDACTED], the Company [REDACTED].

15 This outage spanned [REDACTED] hours and resulted in a replacement power cost of
16 \$[REDACTED].

17 **Q. WHAT IS STAFF’S RECOMMENDATION FOR THIS OUTAGE?**

18 A. Staff recommends the fuel balance be reduced by \$[REDACTED] for the fuel replacement
19 cost associated with the [REDACTED] outage considering that it was caused by

20 [REDACTED] as the Root Cause Analysis (“RCA”) stated.⁶⁷

⁶³ Replacement Power cost from “MFRH-4.2 Attachment M TS.xlsx.”

⁶⁴ “MFRH-4.2 Attachment E TS.docx”

⁶⁵ STF-JKA 4-25.

⁶⁶ MFRH-4.2 Attachment E TS.docx.

⁶⁷ Replacement Power cost from “MFRH-4.2 Attachment M TS.xlsx.”

1 **Q. PLEASE DISCUSS THE [REDACTED] OUTAGE THAT OCCURRED**
2 **JANUARY 23, 2025 TO FEBRUARY 21, 2025.**

3 A. On [REDACTED], the [REDACTED] unit experienced an outage due to [REDACTED]
4 [REDACTED]
5 [REDACTED]. The Event Learning Report
6 stated that [REDACTED]
7 [REDACTED].⁶⁸ The Event Learning Report stated the
8 [REDACTED]. The Company was asked specifically [REDACTED]
9 [REDACTED] and the Company responded, [REDACTED]
10 [REDACTED].⁶⁹ [REDACTED]
11 [REDACTED].
12 The Company noted that this incident led to [REDACTED] forced outage hours, with an estimated
13 damage to equipment of \$[REDACTED], \$[REDACTED] of which was capitalized.⁷⁰

14 **Q. WHAT IS STAFF'S RECOMMENDATION FOR THIS OUTAGE?**

15 A. Staff is not recommending a disallowance at this time as the Company found there was
16 [REDACTED] associated with the outage. However, Staff recommends the
17 Company provide an explanation in Rebuttal Testimony as to why there was [REDACTED]
18 [REDACTED]
19 [REDACTED], which was an expensive month in the historical
20 period.

21 **Q. WHAT IS STAFF'S RECOMMENDATION FOR A DISALLOWANCE**

⁶⁸ MFRH-4.2 Attachment G TS.pdf

⁶⁹ STF-JKA-4-26

⁷⁰ MFRH-4.2 Attachment G TS.pdf, p.3.

RELATED TO THESE THREE OUTAGES?

A. Staff believes the Company was clearly imprudent associated with these outages and recommends a disallowance of approximately \$ [REDACTED] for the replacement power costs as shown in the following table and described below.

Table 13: Avoidable Outage Replacement Power Costs

	Start	End	Replacement Power Cost ⁷¹
[REDACTED]			
Total			

Q. PLEASE DISCUSS THE ADDITIONAL OUTAGES CAUSED BY OPERATOR AND CONTRACTOR ERRORS.

A. The following table indicates the number of outage events and outage hours that occurred over the historical period of January 1, 2023 through December 31, 2025 that were caused by operator or contractor errors.

⁷¹ Replacement Power cost from "MFRH-4.2 Attachment M TS.xlsx."

**Table 14: Outage Hours and Events During the Historical Period
Due to Operator or Contractor Error⁷²**

Unit	Forced Derate and Forced Outage Events	Forced Derate and Forced Outage Hours
Bowen 4		
McDonough 6		
McDonough 4		
McDonough 5		
McIntosh CC 11		
Scherer 3		
McIntosh CC 10		
Bowen 3		
Gaston 4		
Yates 6		
Gaston 1		
Yates 7		
Gaston 3		
Total		

The table indicates that overall the number of these errors was small. In total there were [REDACTED] operator or contractor error events, that lasted [REDACTED] hours. This is very small when considering there are more than 26,000 hours in the period.

Q. DOES STAFF HAVE ANY CONCERN ABOUT THESE OUTAGES?

A. The only possible issue is that multiple operator and contractor errors occurred at the same plant over the historical period, particularly at [REDACTED], which in the future the Company should strive to minimize.

Q. DID YOU ALSO REVIEW GEORGIA POWER'S FCR-27 HISTORICAL PERIOD FOSSIL UNIT PLANNED MAINTENANCE OUTAGES?

⁷² MFRH-4.2 TS.xlsx, Operator or Contractor Error determined by GADS code 9900, 9910, and 9920.

A. Yes, we did. Planned outages are generally scheduled during periods when units are less needed (shoulder months) in order to perform required maintenance on units.⁷³ Our investigation included reviewing planned outages that occurred during the historical period of FCR-27 and compared those to prior FCR proceedings (FCR-24 through FCR-26).

Table 15: Average Lost Generation Due to Planned Outages at Fossil Plants ⁷⁴

	No. of Months in FCR Period	No. of Outages >500,000 MWH	Avg Lost Gen. Per Planned Outage (MWH)
FCR-24			
FCR-25			
FCR-26			
FCR-27			

Q. WHAT DID YOU EVALUATE REGARDING PLANNED MAINTENANCE OUTAGES?

A. Our planned maintenance outage evaluation focused on the number of major planned outages that were greater than 500,000 MWH. For each of those outages, we calculated the average amount of lost generation per outage, and we compared results for FCR-27 to similar results for each FCR historical period going back to FCR-24.

Q. PLEASE DESCRIBE THE RESULTS SHOWN IN THE TABLE.

A. The second column contains the total number of planned outages that resulted in lost generation greater than 500,000 MWH. The average generation lost per planned outage has increased since FCR-26 and is the [REDACTED] average since FCR-20. Aging

⁷³ In contrast, forced outages result from unexpected events that require units to be removed from service immediately.

⁷⁴ STF-JKA-1-1 Attachment A TRADE SECRET.xlsx, (excludes Nuclear and Hydro)

generating units in the fleet could require more planned outages with more extensive maintenance to be done. Staff recommends the Company provide additional explanations in rebuttal testimony of why the planned outages have increased so significantly.

Transmission Outages

Q. DID YOU ALSO REVIEW GEORGIA POWER'S FCR-27 HISTORICAL PERIOD TRANSMISSION OUTAGES AND CONGESTION IMPACTS?

A. Yes, Staff reviewed FCR-27 historical period transmission outages and congestion based on information provided in MFRH 4.4 and primarily focused on the duration of the reported events, replacement power costs, and the provided transmission outage/congestion descriptions. Staff also reviewed the root cause analysis for all transmission outages that lasted longer than 10 days and vegetation management reports for transmission line segments with more than 10 outages during the review period. There did not appear to be any excessively long transmission outages or congestion that resulted in significant replacement power costs, however Staff notes there were impacts to various solar facilities. Specifically, local transmission area issues impacted the [REDACTED] solar [REDACTED] Solar [REDACTED] facilities during the historic period.⁷⁵ Additionally, local transmission area work impacted [REDACTED] and [REDACTED].⁷⁶

Winter Storm Impacts

Q. DID STAFF REVIEW HOW THE COMPANY'S SYSTEM PERFORMED

⁷⁵ STF-JKA-5-24 Attachment TRADE SECRET indicates the [REDACTED]

⁷⁶ STF-JKA-5-24 indicates that the [REDACTED]

DURING FCR-27 HISTORIC PERIOD WINTER STORMS?

A. Yes. The Company provided a load and resource assessment for each historic month describing unavailable generation and reserve margin for peak hours. The following table summarizes the generator performance in peak winter hours.

Table 16: Winter Peak Hour Reserve Margin ⁷⁷

Peak Hour	GPC peak hour load	GPC Retail Capacity	Reserves (Capacity - Load)	Unavailable Generation	Reserve Margin Total Generation	Reserve Margin Available Generation
EPT HE	(MW)	(MW)	(MW)	(MW)	%	%
1/24/2023 8:00	14,035	19,661	5,626		40.09%	
1/17/2024 8:00	16,458	19,874	3,416		20.76%	
1/24/2025 8:00	15,957	20,632	4,676		29.30%	

January 2025 was the most expensive month in the historic period, and compared to January 2023 and 2024, had the highest amount of unavailable generation. The following table provides a breakdown of the resource type and plant impacted in each winter hour.

⁷⁷ STF-JKA-1-43 Attachment Supplemental TRADE SECRET.xlsx (3/30/2026).

Table 17: Winter Peak Hour Generation Unavailable (MW) ⁷⁸

Type	Resource	2023	2024	2025
Coal				
Coal				
Combined Cycle				
Combustion Turbine				
Combustion Turbine				
Combustion Turbine				
Hydro				
Nuclear				
Nuclear				
Grand Total				

The [REDACTED] outages from January 2025 and the [REDACTED] outage from January 2024 were examined in detail, and Staff's recommended disallowances are discussed above.

Q. HAS THE COMPANY IDENTIFIED ANY MEASURES IT HAS OR PLANS TO UNDERTAKE TO REDUCE THE RISK OF FUTURE GENERATOR OUTAGES CAUSED BY EXTREME WINTER WEATHER EVENTS?

A. The majority of the outages in the winter peak did not appear to be winter weather related, however the Company continues to work to investigate and improve equipment that could be impacted by winter storms. The Company states that it has completed the majority of planned work for compliance with NERC standards, with only minor work remaining. The Company has also added radiant heaters to inverter housing at Georgia Power's solar sites at Robins, Fort Stewart, and Fort Gordon.⁷⁹

Carrying Costs

⁷⁸ STF-JKA-3-3 Attachment A TRADE SECRET.xlsx.

⁷⁹ STF-JKA-5-23

Q. DID THE COMMISSION PREVIOUSLY AUTHORIZE THE COMPANY TO RECOVER CARRYING COSTS ON UNDER-RECOVERED FUEL COST BALANCES?

A. Yes. In Docket No. 17066 the Commission approved the accrual of carrying costs, calculated based upon Georgia Power's short-term debt rate applied to the under-recovered balance, net of accumulated deferred income taxes, above the first \$15.0 million.

Q. DID YOU REVIEW THE COMPANY'S CARRYING COST CALCULATION?

A. Yes. MFRH-15 shows the computation of monthly carrying costs based on Georgia Power's actual average short-term debt rates during the historical period. Historically before the COVID-19 pandemic, the Company had relied upon commercial paper to meet most of its short-term debt needs.⁸⁰ According to the Company, COVID-19 caused a period of significant stress in the financial markets, including very little liquidity supply in the commercial paper market.⁸¹ Beginning at that time in 2020 and continuing for much of the time through May 2025, the Company reported that it relied more heavily on large amounts of short-term bank term loans and uncommitted credit lines in addition to commercial paper. This reliance was compounded by the large longer-term under-recovered fuel cost balances that exceeded \$2 billion by the start of the historical period. For example, the Company reported that "given the size of the under-recovered fuel balances accumulated throughout 2022, the Company entered a \$1.2 billion syndicated short-term bank loan in November 2022 to support carrying the large under-recovered

⁸⁰ Response to STF-JKA-3-34 (a) and (b)

⁸¹ *Id.*

1 balance on the balance sheet.”⁸² This one loan in particular carried many differing
2 balances until it was finally converted to long-term debt in June 2025.⁸³ These kinds of
3 short-term financial transactions typically carry higher interest rates than commercial
4 paper.

5 The short-term bank loans were priced at the 1-month Secured Overnight Finance
6 Rate (“SOFR”) with a credit spread and the more limited uncommitted credit line during
7 the historical period was priced at a rate agreed upon between the bank and the Company.
8 The Company forecasts its short-term debt rates for the forecast period by using the
9 Bloomberg SOFR forward curve forecast and adding a spread of 50 basis points to act as
10 a reasonable proxy for commercial paper rates it expects to obtain.⁸⁴ As long as the spread
11 being added to SOFR approximates 50 basis points for the short-term bank notes, average
12 interest rates have traditionally been close to commercial paper rates. Some of the short-
13 term bank notes during the historical period were based on the SOFR + 50 basis points
14 spread. However, the Company also had to agree to pay spreads of as high as 80 to 105
15 basis points with some institutions in order to obtain the high levels of short-term
16 financing with longer terms required to finance the large under-recovered fuel cost
17 balances during that period.⁸⁵ Once the under-recovered fuel cost balances were lowered
18 to levels under \$1 billion midway through 2025, Georgia Power reported it was able to
19 once again begin utilizing only commercial paper to serve its short-term financing
20 needs.⁸⁶

⁸² Response to STF-JKA-3-34 (c)

⁸³ *Id.*

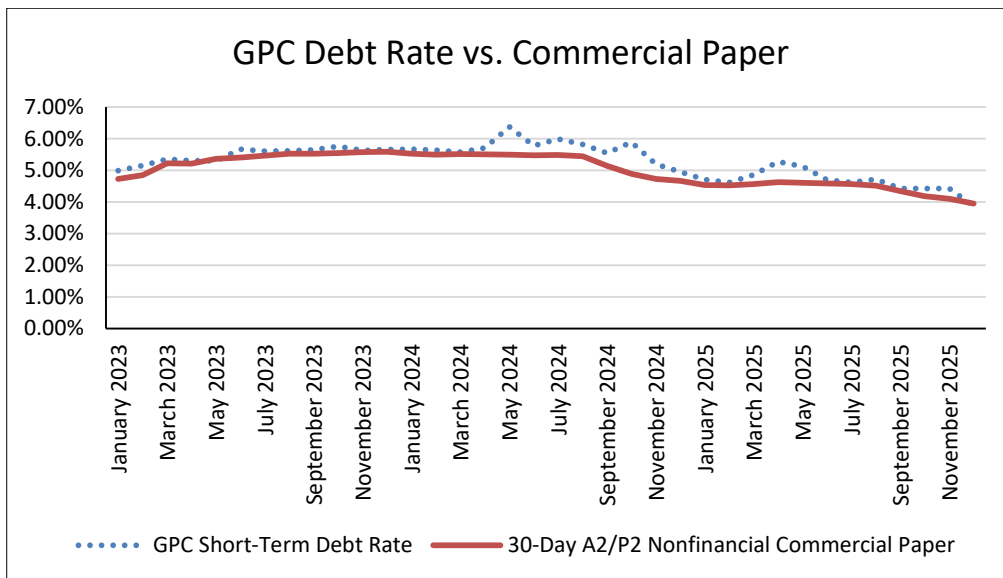
⁸⁴ Response to STF-JKA-1-29

⁸⁵ Response to STF-JKA-3-33

⁸⁶ Response to STF-JKA-3-34 (e)

The short-term debt rate was relatively higher during most of the historical period as compared to prior periods. The average short-term debt rates applied to net under-recovery balances averaged 5.40% over the entire historical period. Due to Georgia Power's reliance on the alternative short-term financial transactions, the average short-term rates were mostly higher than the 30-day A2/P2 Nonfinancial Commercial Paper average interest rates, as seen in Figure 5 below.⁸⁷

Figure 5: GPC Debt Rate vs. Commercial Paper



This was especially the case when the outstanding debt in any one month was more representative of the notes with credit spreads exceeding 50 basis points such as in May 2024, October 2024, and April 2025. When the cumulative fuel balance is over-recovered, ratepayers receive a credit for carrying costs, and when the balance is under-recovered, ratepayers receive a charge for carrying costs. Overall during the historical period, net carrying costs charged to customers amounted to \$184.7 million. Had carrying

⁸⁷ Federal Reserve Bank of St. Louis, Federal Reserve Economic Data, 30-Day A2/P2 Non-Financial Commercial Paper Interest Rate, <https://fred.stlouisfed.org>.

1 costs been computed based only on the 30-day A2/P2 Nonfinancial Commercial Paper
2 average interest rate each month, customers would have been charged only \$176.5
3 million, a reduction of \$8.2 million. Ratepayers should not be held entirely responsible
4 for Georgia Power's reported need to utilize high levels of short-term bank term loans
5 with higher interest rates during the historical period.⁸⁸ There were some months when
6 the level of commercial paper exceeded \$800 million, while there were others in which
7 no commercial paper was utilized.⁸⁹ From the Trade Secret MFR workpapers included
8 in the Company's filing, it appears that the Company issued commercial paper with terms
9 of [REDACTED] or less in all circumstances.⁹⁰

10 Staff believes that some level of short-term bank loans was reasonable as Georgia
11 Power needed short-term financing for 2023 and 2024 until the unrecovered fuel costs
12 balance was paid down. Staff understands that there is no guarantee that commercial
13 paper would be available or at favorable terms when it needed to be renewed, so it would
14 be unreasonable to rely solely on commercial paper at such high levels. However, the
15 Company should have utilized longer term commercial paper (60 days or 90 days) to
16 reduce some of the higher cost bank loan borrowings during the period. There were eight
17 months in the historical period in which the carrying costs were especially higher than
18 they would have been utilizing the 30-day A2/P2 Nonfinancial Commercial Paper
19 benchmark. The excess interest expense in those eight months amounts to \$3.8 million
20 and is an example of the Company's inefficiency resulting in higher fuel cost for
21 ratepayers.

⁸⁸ Response to STF-JKA-3-34(c)

⁸⁹ Response to STF-JKA-3-35

⁹⁰ Refer to MFRH-15 Attachment (TRADE SECRET)

Purchased Power

Q. DID STAFF REVIEW PURCHASED POWER CONTRACTS AS APPROPRIATE FOR FUEL COST RECOVERY?

A. Yes. Staff reviewed the summary of each purchased power agreement contract provided with MFRH-13.2. The Company asserted it only charged costs related to fuel and energy, as demand related charges are recoverable through base rates.⁹¹ For example, the Company entered into a capacity agreement with Mississippi Power Company (“MPC”), which began January 1, 2024. The Company stated the energy associated with the MPC purchase flows through as pool purchases.⁹² The Company also provided pool settlement data in MFRH-13.1, which includes details related to Fuel Payments received from the Pool and Fuel Payments made to the Pool, which did not appear to include Capacity related charges.

Opportunity Sales

Q. PLEASE DESCRIBE YOUR INVESTIGATION REGARDING OPPORTUNITY SALES.

A. Staff examined the level of profits shared between the Company and customers. Currently, the Company is entitled to keep 25% of the profits.⁹³ During FCR-27 historic period, the total profits the Company achieved from making these sales was \$26.4 million, with \$20.5 million going to ratepayers, after accounting for adjustments, hedging impacts, and Company profits.⁹⁴ On a projected basis, the Company anticipates reduced

⁹¹ STF-PIA-3-2 and STF-PIA-3-3

⁹² STF-JKA-2-32

⁹³ See the Commission's 1989 Order in Docket 3840.

⁹⁴ STF-JKA-1-15 and STF-JKA-3-26, which notes a correction related to a June 2023 capacity sale.

1 opportunity for such sales, as shown in NHSW-5. Staff does not oppose continuing the
2 sharing mechanism at this time.

3 **V. PROJECTED TEST PERIOD REVIEW**

4 **Natural Gas Price Forecast Assumptions**

5 **Q. PLEASE DISCUSS GEORGIA POWER'S FCR-27 NATURAL GAS PRICE**
6 **FORECAST THAT WAS USED IN DEVELOPING ITS PROJECTED RATE.**

7 A. The natural gas price forecast (B2026 forecast) that Georgia Power used to produce its
8 fuel budget projection was developed in August 2025.

9 **Q. HAS STAFF EVALUATED THE COMPANY'S GAS PRICE FORECASTS IN**
10 **LIGHT OF RECENT MARKET DATA?**

11 A. Yes, Staff has reviewed the Company's B2026 forecast that underpins the filing. Staff
12 provides the following graph that compares the Company's B2026 forecast to a more
13 recent NYMEX projection from April 1, 2026.

Figure 6: Gas Forecast vs. NYMEX⁹⁵



The most recent NYMEX projection is close to the Company's projection for the entire period, though some of the time, the NYMEX projection is a little above the Company's forecast, and part of the time the NYMEX projection is a little below the Company's forecast. The differences in the projections do not appear to be significant.

Fuel Projection Generation Mix

Q. HOW WILL GEORGIA POWER'S PROJECTED MIX OF GENERATION CHANGE OVER TIME?

A. The following table compares the percentage of generation energy by resource type that are projected to supply the forecast load during the FCR-27 projected period. The table also includes actual historical data for 2023, 2024, and 2025 for comparison purposes.

⁹⁵ "MFRP-6.4 TS.xlsx" and NYMEX values from April 1, 2026.

Table 18: Projected Fuel Source Comparison (% Generation) ⁹⁶

	% Generation Energy					
	Actual 2023	Actual 2024	Actual 2025	Projected Jun 26- May 27	Projected Jun 27 - May 28	Projected Jun 28 - May 29
Natural Gas	33.1%	30.1%	26.5%	27.1%	24.7%	23.8%
Coal Steam	12.8%	13.0%	13.7%	16.4%	15.1%	15.2%
Nuclear	20.3%	23.9%	23.6%	23.1%	20.3%	17.7%
Purchased Power	23.9%	21.7%	24.2%	19.9%	27.8%	31.7%
Hydro	1.4%	1.3%	1.4%	1.3%	1.1%	1.0%
Solar	5.2%	6.9%	7.8%	9.3%	8.6%	8.6%
Biomass	2.5%	2.4%	2.1%	2.5%	2.2%	2.0%
Wind	0.8%	0.7%	0.7%	0.5%	0.4%	0.4%
BESS	0.0%	0.0%	0.0%	-0.1%	-0.2%	-0.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The table indicates that the amount of coal generation use actually increases a small amount over time, likely because of growing retail load. Natural Gas appears to be declining while Purchase Power is increasing, but that does not necessarily mean that natural gas resources are becoming less utilized, as much of the purchase power will come from natural gas based resources. The fact that the nuclear energy percentage declines relates to the fact that nuclear energy is maxed out already, and therefore as load grows the percentage of nuclear energy in the mix will decline.

The following figure provides the generation composition on an energy (GWh) basis. It indicates that to meet growing energy requirements, the Company expects it will rely on additional purchased power, in addition to increased generation from coal and natural gas generation.

⁹⁶ Actual values were obtained from “MFRH-2 TS.xlsx” and Projected values were obtained from “MFRP-1 FCR-27 Budget TS.xlsx.”

Figure 7: Projected Fuel Source Comparison (GWh)



The increase in purchase power is predominately driven by increasing reliance on pool purchases and the Southern Power PPAs (Harris and Wansley) as shown in Exhibit NHSW-5. Reliance on purchase power beyond the 24-month historic period increases risks of market cost exposure.

Renewable Procurement Costs

Q. ARE THE COSTS OF RENEWABLE ENERGY PROGRAMS INCLUDED IN FCR RATES?

A. Yes. The following table describes the various renewable programs and costs the Company expects to incur between June 2026 - May 2028.

**Table 19: Renewable Program Costs
Projected Period (June 2026-May 2028)**

Revenues / (Costs)	Program Revenues	Labor Expenses	Other Expenses	REC expenses	Additional Sum, Transmission & Renewable Integration	TOTAL
Simple Solar Program						
Flex RECs Program						
REDI C&I Program						
CRSP Program						
CARES Program						
CARES DG Program						
CARES (Residential Solar)						
Retail REC Retirement (R3)						
Behind the Meter Program						
Distributed Generation						
Utility Scale						
Additional Expenses (555)						
Total Renewable Programs						
RFP related ⁹⁷						

For Renewable Energy Certificate (“REC”) programs, the Company used the 2025 actual costs as basis for the projection, and assumed a 3% escalation each year.⁹⁸

Q. DID THE COMPANY IDENTIFY PROCUREMENT RELATED COSTS FOR RENEWABLE ENERGY AS A COST TO BE RECOVERED THROUGH THE FCR?

A. Yes. The Company requested the Commission authorize Georgia Power to recover all Renewable RFP (utility scale and distributed generation) and renewable subscription program-related costs not otherwise recovered by the Company through Bid Fees and Winner’s Fees, through the fuel clause. The Company currently expects costs of all

⁹⁷ STF-JKA-2-29 b.

⁹⁸ STF-JKA-2-31.

renewable programs to exceed revenues by [REDACTED] over the 24-month projected period, as shown in the table above.

Q. WHAT IS STAFF’S RECOMMENDATION REGARDING RENEWABLE ENERGY PROGRAM COSTS THAT EXCEED REVENUES BEGINNING JUNE 2026?

A. Excess costs should be placed in a regulatory asset for consideration by the Commission in the next base rate case. In the 2022 IRP Stipulation, Parties anticipated “Bid and winners’ fees will be set to recover the total cost of procurement for the RFP solicitation.”⁹⁹ Future treatment of Renewable Energy Program costs, including Company labor, should be addressed in the next base rate case.

Furthermore, the Company should specifically itemize revenues and the costs related to administration of renewable programs and RFPs using the same metrics for both the historical and projected periods, such that the projected amounts can be readily compared to historical period amounts on a one-to-one basis.¹⁰⁰ Staff recommends the Company provide a side by side comparison of the net renewable costs from the historic period and the projected period quantifying the impact of the Company’s Renewable RFP cost recovery request in the context of total program costs and revenues in Rebuttal Testimony.

VI. OTHER ISSUES

Economic Development and Large Loads

Q. HAVE YOU EVALUATED LARGE LOAD GROWTH IMPACT ON THE

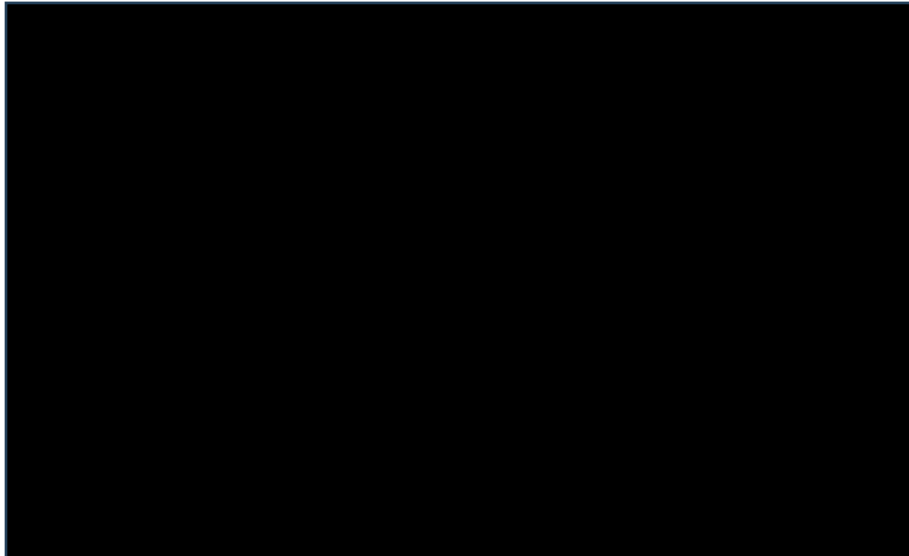
⁹⁹ 2022 IRP Stipulation Item 22, DG RFP

¹⁰⁰ STF-JKA-2-30 and STF-PIA-5-1.

PROJECTED PERIOD?

A. Yes. The Company anticipates a significant amount of new large load will be added to the Company's load requirement over the FCR projection period. The following figure shows the projected growth in Commercial Large Data Center Load by month. This category of load is anticipated to increase steadily over time and will be about [REDACTED] greater by May 2028.

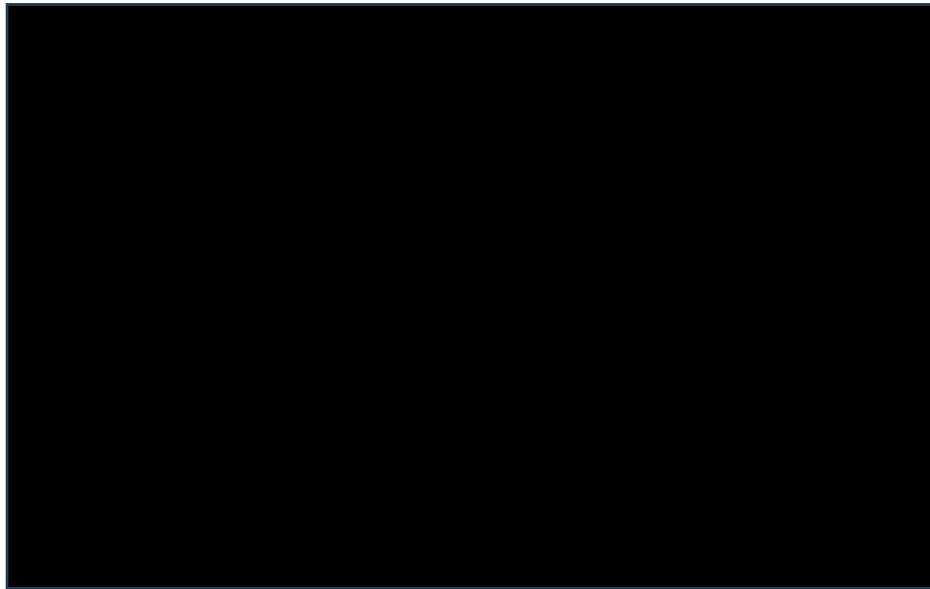
Figure 8: Large Load in FCR Projection¹⁰¹



Staff assessed the impact of this additional load by removing it from the Company's modeling database and then Aurora was re-run. The following table compares the portfolio level (Georgia Power assigned) average cost derived from the Aurora projection with and without this high load factor customer load.

¹⁰¹ STF-JKA-1-27.

Figure 9: Projected Impact of Large Loads



The additional large load drives up the average fuel cost (\$/MWh) in each month by approximately 5 - 11% in 2028, and the difference increases over time as more large load is added to the system. An increased amount of purchases, natural gas and coal-fired generation is required to serve the additional data center load. Specifically, the total increase of generation appears to be driven by a few plants, including purchases from [REDACTED], as well as Company generation from [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED].¹⁰²

Q. HOW WILL LARGE LOAD CUSTOMERS CONTRIBUTE TO PAYING FOR THE FUEL COST RECOVERY?

A. The Company explained how large load customers will contribute to paying for the fuel

¹⁰² Staff estimated values from Aurora results.

cost recovery as follows:

[M]uch of the KWh sales from these large load customers is priced at RTP. For RTP load, a large load customer's fuel contribution reflects the marginal costs incurred by the Company in each hour. Further, large load customers bear the risk of higher fuel prices and are assessed those costs directly during higher cost hours. Thus, large load customers will bear the appropriate cost responsibility in each hour for the fuel cost they impose on the Company [...]¹⁰³

The Company acknowledged the growth of RTP load corresponding to new economic development load and asserts RTP customers pay a fair share of the fuel costs.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF RTP.

A. An RTP customer is charged an RTP price (\$/MWh) in each hour for the amount of energy (MWhs) that is consumed above a threshold amount, as established in the customer's contract with Georgia Power.¹⁰⁴ The RTP revenues the Company receives are credited as either fuel revenues or base revenues. The Company explains:

A portion of that component of RTP price, the average marginal fuel cost of all Georgia Power units running in each hour, covers fuel costs and is accounted for as fuel revenue. The difference between lambda and the allocated fuel revenue covers two pieces: generation variable O&M and capital substitution. The capital substitution contribution covers additional fixed costs associated with resources that support lower fuel costs, including capital costs for baseload generation and firm transportation (FT).¹⁰⁵

For purposes of this proceeding Staff focused on the amount of RTP revenues credited to the fuel balance rather than the RTP rate charged to RTP customers.

Q. HOW DO HISTORICAL FUEL CREDITS ASSOCIATED WITH THE RTP LOADS COMPARE TO AVERAGE FUEL COST FOR THE SYSTEM?

A. The following table compares the average RTP fuel credit to the average fuel cost

¹⁰³ Direct Testimony of Adam D. Houston and Matthew S. Berrigan, p. 18, ll. 1-8

¹⁰⁴ The threshold is referred to as the Customer Base Line (CBL). The CBL can vary from customer to customer.

¹⁰⁵ STF-JKA-1-7 part d.

incurred by month through the historic period (January 2023-December 2025).¹⁰⁶

Table 20: RTP Fuel Credit vs. Avg. Fuel Cost \$/MWh¹⁰⁷

2023	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
Fuel Cost (Supply)													
RTP Fuel Credit													
Delta	\$0.45	\$4.95	\$8.47	\$7.40	\$11.06	\$12.39	\$15.12	\$9.14	\$6.19	\$8.53	\$7.78	\$8.52	\$8.55

2024	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg.
Fuel Cost (Supply)													
RTP Fuel Credit													
Delta	\$11.86	\$1.62	\$7.57	\$12.80	\$11.59	\$11.99	\$9.92	\$6.85	\$8.17	\$7.91	\$6.66	\$8.68	\$9.06

2025	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Fuel Cost (Supply)													
RTP Fuel Credit													
Delta	\$15.35	\$4.28	\$11.92	\$8.87	\$8.09	\$9.71	\$8.06	\$3.08	\$6.85	\$6.54	\$7.32	\$8.35	\$8.36

The average RTP fuel revenue rate credited to fuel revenues was below the average fuel cost in every month of the historic period, and on average the average RTP fuel credit to fuel revenues was approximately \$9/MWh less than average supply rate each year. This indicates that on average, RTP customers may be paying less for fuel than non-RTP customers.¹⁰⁸

Q. WHAT IS STAFF’S RECOMMENDATION REGARDING THE DISCREPANCY BETWEEN FUEL COST INCURRED AND THE RTP FUEL CREDIT?

A. Staff is concerned the RTP fuel credit may not be sufficient, and recommends the Commission open a docket to further investigate this issue. An RTP customer is assessed an RTP price every hour in which its load exceeds its customer baseline. The amount of fuel revenues credited to the fuel balance is derived based on the average “marginal” cost

¹⁰⁶ Supply Costs includes owned generation and purchased power costs, but excludes hedging, carrying costs, renewable programs, and other miscellaneous adjustments.

¹⁰⁷ STF-JKA-3-8 (MWh), STF-JKA-3-4 (Fuel Credit), MFRH-2 TS.xlsx (Supply Costs \$/MWh).

¹⁰⁸ The annual impact could be near \$200 million if assuming 20 million MWh of RTP load and a \$10/MWh differential between fuel credit and average fuel cost.

1 of Georgia Power owned generation, pool purchases, and PPAs, for each hour.¹⁰⁹ The
2 amount of the credit in an hour can be higher than the average fuel cost in the hour if
3 marginal fuel prices are high and incremental generation costs are expensive. Conversely,
4 the hourly credit may be lower than the average fuel cost if efficient units are available
5 for dispatch and under-utilized by the existing load. Given the hourly granularity driving
6 RTP revenues and RTP fuel revenue credits, significant amounts of hourly load and
7 dispatch data need to be analyzed to develop an understanding of whether the RTP
8 revenues credited to fuel revenues is sufficient and reasonable. Additional discussion
9 about the RTP mechanism is provided below.

10 **Real Time Pricing**

11 **Q. IS STAFF CONCERNED ABOUT THE RTP FUEL CREDIT METHODOLOGY?**

12 A. Yes. Recognizing that large RTP loads are growing significantly, Staff wants to ensure
13 that a reasonable amount of the RTP revenues are being credited to fuel revenues. Staff
14 is particularly concerned about the treatment of FT costs and the way those are being
15 credited to the fuel recovery balance. FT costs incurred by the Company are considered
16 a fuel cost and recovered through the FCR. However, the RTP revenue credit
17 methodology does not assume an assignment of RTP revenues for FT costs to the FCR.¹¹⁰

18 **Q. DO YOU HAVE SPECIFIC CONCERNS REGARDING FT COSTS AS IT** 19 **RELATES TO RTP CUSTOMERS?**

20 A. Yes. FT costs are passed to customers through the FCR balance, but it does not appear
21 that RTP revenues are used to offset FT costs based on the current RTP credit

¹⁰⁹ STF-JKA-1-7.

¹¹⁰ STF-JKA-1-7 part d.

1 methodology.¹¹¹ It is unclear how FT costs are recovered through the
2 reliability/capacity/lambda portion of the RTP charge to customers, but it is clear that
3 those FT related collections are not credited back to the FCR balance.¹¹² This appears to
4 indicate that RTP customers relying on system capacity, some of which would require
5 FT, do not pay for FT costs. Staff recommends that the Company provide a thorough
6 explanation of this possible discrepancy in rebuttal testimony, and in the future, modify
7 the RTP credit methodology to include an FT cost component calculated similar to the
8 capacity or transmission components. This would ensure that fixed capacity-related FT
9 costs are shared by all load served during peak events.

10 **Q. HOW ARE THE CAPACITY AND TRANSMISSION COMPONENTS**
11 **DERIVED?**

12 A. The Company explained that it recovers transmission and capacity costs in RTP rates
13 over a limited number of peak hours, so that the RTP load online during peak events pay
14 for capacity and transmission costs required to serve load in peak hours.¹¹³ FT is used to
15 support the capacity available in all summer and winter reliability hours and supports all
16 firm customer load (including RTP customer load). For the historic period, Staff has
17 estimated that the RTP credit methodology resulted in a potential shortfall of
18 approximately \$57.6 million that should have been credited to fuel. The following table
19 provides the historic period annual FT costs and a ratio allocation based on the historic

¹¹¹ STF-JKA-3-4

¹¹² STF-PIA-3-11 part c (transmission) and d (reliability capacity) indicate that none of the transmission or reliability capacity costs collected in RTP rates are assigned to the FCR as RTP fuel revenue.

¹¹³ STF-JKA-1-5, "For the reliability capacity costs, the respective amount is included when system loads are greater than the 50th highest forecasted load for the year. These costs are designed to be recovered over these 50 hours in a weather normal year. For the transmission capacity costs, the respective amount is included when system loads are greater than the 300th highest forecasted load for the year, adjusted for ambient temperature. These costs are designed to be recovered over these 300 hours in a weather normal year."

RTP customer load in the peak (summer) hour.

Table 21: FT Costs and RTP Load at Summer Peak (Historic)

Year	FT Cost ¹¹⁴ (\$million)	RTP MW ¹¹⁵	GPC Summer Peak ¹¹⁶	RTP % (estimated)	RTP % FT (\$million)
2023					
2024					
2025					
Total					\$57.6

Q. DOES STAFF HAVE ANY OTHER CONCERNS REGARDING THE RTP CREDITING METHODOLOGY?

A. Yes. Staff is also concerned that take-or-pay contracts may not be included in the average marginal cost calculation used to set the RTP revenue credit price.¹¹⁸ The Company's approved fuel credit methodology implies that all generation and purchases used to serve Georgia Power load is averaged together to determine average marginal fuel cost each hour. Given these purchase contracts were used to serve load during the hour, it follows that these contracts should be included in the calculation average fuel cost. The Company confirmed that not all generation is included in the average.¹¹⁹ It appears that if the approved methodology requires the marginal fuel expense of all generation resources in a given hour be included when calculating RTP credit to fuel balance, then the most expensive take-or-pay contracts should be included as well. Staff has not estimated the

¹¹⁴ MFRH-2 TS.xlsx

¹¹⁵ STF-JKA-3-8.

¹¹⁶ STF-JKA-1-8.

¹¹⁷ STF-JKA-1-4 Attachment B supplemental was provided 3/30/2026 providing correction to RTP load in this hour at [REDACTED] MW.

¹¹⁸ STF-JKA-6-1 (Pending).

¹¹⁹ STF-PIA-3-14.

1 impact of the inclusion of these contract costs, as it requires review of the hourly unit
2 dispatch data for each historic hour, which was not available at the time of preparing this
3 testimony. This analysis would be included in the investigation recommended by Staff.¹²⁰

4 **Q. WOULD MODIFYING THE RTP CREDIT METHODOLOGY TO ALLOCATE**
5 **RTP REVENUES TO FUEL RECOVERY BALANCE AFFECT THE COSTS**
6 **CHARGED TO RTP CUSTOMERS?**

7 A. No. The issue relates to what RTP revenues are credited to the fuel bucket, not the rate
8 RTP customers are charged. Furthermore, Staff's proposed credit adjustments relate to
9 the crediting methodology that was changed going back to the Company's 2010 rate case:

10 [T]he Company is also proposing to change its accounting methodology for
11 crediting the Fuel Cost Recovery ("FCR") account from RTP usage. At
12 present RTP credits the fuel account at current FCR rates. The Company is
13 proposing to use an average hourly marginal replacement fuel cost to credit
14 the fuel account. This average hourly marginal fuel cost will be based on
15 all Georgia Power generating units running in each hour plus power pool
16 purchases or deliveries in each hour.¹²¹

17
18 The Company describes the 2010 rate case approved methodology as reasonable, but it
19 is unclear if the specific treatment of whether take-or-pay contracts would be considered
20 a Georgia Power generating unit or "delivery" in the hour for purposes of setting the
21 credit amount.

22 **Q. DOES STAFF HAVE ANY OTHER CONCERNS REGARDING THE RTP**
23 **CUSTOMERS?**

24 A. Yes. Staff is concerned about the projected growth in RTP customer sales over the next
25 few years, specifically new data center load expected to take service on such rates. The

¹²⁰ STF-JKA-6-1 (Pending).

¹²¹ STF-JKA-3-10 Attachment A (Docket 31958, Direct Testimony of Gregory Roberts, p. 12, ll. 17-24).

following table shows the RTP sales trend through the historic and projected period.

Table 22: RTP Sales (MWh) ¹²²

Year	RTP Sales
2023 (Historic)	
2024 (Historic)	
2025 (Historic)	
2026 (Projected)	
2027 (Projected)	
2028 (Projected)	

Q. DOES STAFF HAVE AN ADDITIONAL RECOMMENDATION TO ADDRESS THE SIGNIFICANT GROWTH?

A. Yes. Staff recommends that the Commission open a docket to further assess RTP matters. Much of the hourly data to perform RTP analysis is voluminous, and additional time to consider the mechanics in light of specific actual and forecasted data may be warranted. Staff continues to recommend additional investigation into the RTP fuel credit methodology to assess this cost dynamic and future impacts associated with growing RTP customer load in the projected period.

Q. HAS THE COMMISSION INVESTIGATED RTP RELATED RATE ISSUES IN THE PAST IN A SEPARATE PROCEEDING?

A. Yes. As noted by the Company in response to discovery, the Commission examined the RTP rates in Docket 11708 and issued an order in April 2000. At the time, issues related to the fuel account crediting, risk adders, and the relative relationship between embedded generation costs and fuel rates were examined. Given the magnitude of the growth in RTP load, Staff believes another examination of RTP related issues is warranted.

Natural Gas Price Hedging Program

¹²² MFRP-1 FCR-27 Budget TS.xls tab: RTP (Projected) and STF-JKA-3-8 (Historic)

Q. WHAT DID THE COMPANY STATE IS THE PURPOSE OF ITS NATURAL GAS HEDGING PROGRAM?

A. The Company fuel hedging procedures state “the objective of its natural gas hedging program is to use financial hedging tools to dampen the impacts of upside price volatility, with an emphasis on cost stability and volatility reduction based on information available at the time the decisions were made, rather than achieving the lowest possible realized fuel cost in hindsight.”¹²³

Q. DID THE HEDGING PROGRAM “DAMPEN THE IMPACTS OF UPSIDE PRICE VOLATILITY” DURING 2023 - 2025?

A. No. Figure 2 above shows four spikes in physical natural gas prices in January 2024, January 2025, March 2025 and December 2025. The three significant natural gas spikes that occurred during the historic period were associated with Winter Storm Heather in January 2024, Winter Storm Cora in January 2025, and Winter Storm Enzo in February 2025. Notably the Company’s hedging program resulted in losses of \$ [REDACTED], \$ [REDACTED], and \$ [REDACTED] in those months. In fact, the Company only had [REDACTED] month in the historic period with a hedging gain.¹²⁴ The hedging program did not mitigate or offset higher natural gas costs in three of the four months. In those three months losses on the hedging program increased fuel cost.

Q. IS NATURAL GAS HEDGING PROGRAM NECESSARY TO PROVIDE STABLE FUEL RATES FOR CUSTOMERS?

A. No. The mechanism for providing stable fuel *rates* is accumulating under collection or

¹²³ STF-JKA-2-3 Attachment B.

¹²⁴ MFRH-10 Attachment TS

1 over collection of fuel revenues relative to fuel cost in a separate fuel balance. The fuel
2 balance is amortized evenly over time. The Company receives carrying cost on the fuel
3 balance. Carrying cost represents the cost of obtaining stable fuel rates that do not
4 fluctuate with changes in fuel cost from month to month.

5 **Q. DID THE CUSTOMERS BENEFIT FROM THE COMPANY'S HEDGING**
6 **PROGRAM OVER THE HISTORIC PERIOD?**

7 A. No. The Company reported over \$273 million dollars in losses during 2023-2025.¹²⁵ This
8 equates to a loss of about \$[REDACTED]/MMBTU for all options during the historic period and
9 \$[REDACTED]/MMBTU for all swaps during the historic period. In total the Company's
10 hedged volume over the historic period was [REDACTED] MMBTU losing an average of
11 [REDACTED] hedged.¹²⁶ The Company hedged on average about 32 percent of their
12 projected burn volume for the historic period 2023 -2025.

13 **Q. WHAT IS THE HISTORICAL PERFORMANCE OF THE COMPANY'S**
14 **NATURAL GAS HEDGING PROGRAM?**

15 A. The Company has lost \$753 million during 2006 – 2025. The positive values in the table
16 below represent hedging program losses and increases in fuel cost and the negative values
17 represent hedging program gains and decreases in fuel cost.

¹²⁵ MFRH-10 Attachment TS.

¹²⁶ STF-JKA-2-3 Attachment A TRADE SECRET

Table 23: Hedging Costs (\$millions)

Year	2005	2006	2007	2008	2009	2010	2011
Incremental Costs	\$64	\$80	\$68	\$6	\$186	\$90	\$105
Cumulative Costs	\$64	\$144	\$212	\$218	\$404	\$494	\$599

Year	2012	2013	2014	2015	2016	2017	2018
Incremental Costs	\$84	\$33	\$11	\$24	\$10	(\$1)	(\$12)
Cumulative Costs	\$683	\$716	\$727	\$751	\$761	\$760	\$748

Year	2019	2020	2021	2022	2023	2024	2025
Incremental Costs	\$21	\$54	(\$95)	(\$247)	\$125	\$114	\$33
Cumulative Costs	\$769	\$823	\$728	\$481	\$606	\$720	\$753

The Company acknowledges that it engages in hedging to help mitigate the risk of upward price volatility in the natural gas markets, it is clear that the program results in an overall increase in fuel costs to customers. Since 2005 the Company has provided a benefit (in the form of fuel cost savings) to customers in four years and clearly increased fuel costs for customers in seventeen years ultimately costing customers three quarters of a billion dollars over that time.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY'S NATURAL GAS HEDGING PROGRAM?

A. The natural gas hedging program should be terminated. The hedging program is not necessary to provide stable fuel rates for customers and has significantly increased ratepayer fuel cost over its history. For these reasons the program should be terminated.

Q. HAS THE COMPANY REQUESTED ANY CHANGES TO ITS HEDGING PROGRAM IN ITS FCR-27 APPLICATION?

A. Yes. The Company is requesting the limits of the hedging program be increased to 60% from current 40% of its budgeted natural gas burn and up to 48 months out from current

36 months. These increases in program limits combined with higher volumes of gas burn in 2026 - 2029 would result in the Company hedging significantly higher volumes of natural gas. For example, if the Company were to hedge 60% of their projected natural gas burn it would amount to approximately [REDACTED] MMBtu hedged in 2027, an increase of 91% from the volume hedged in 2025.¹²⁷ Given the program's past performance it is possible that larger losses could occur if the Company's limit modification request was granted.

If the Commissions were to allow the continuation of the hedging program, the Company should only be allowed to hedge up to 30% of projected burn and 24 months in advance. This will keep the volume of future hedges in line with the current amount and could limit potential losses. In addition, the Company should be required to provide transaction level hedging support in its annual filings to allow for additional review of the program.

Q. HAVE UTILITIES IN THE SOUTHEAST UNITED STATES TERMINATED THEIR NATURAL GAS HEDGING PROGRAMS?

A. Yes. In Florida for example, a moratorium on natural gas financial hedging was issued in Docket No. 160001-EI by Order No. PSC-16-0547-FOF-EI as a result of over \$6.5 billion in cumulative losses by the investor-owned utilities.¹²⁸ The Florida Commission issued Order PSC-2017-0451-AS-EU, which suspended the natural gas financial hedging for Duke Energy Florida through December 2021. Duke Energy Florida again agreed through Settlement to not execute any new natural gas financial hedging contracts

¹²⁷ STF-JKA-2-3 Attachment A, [REDACTED] MMBTU Hedged Volume in 2025

¹²⁸ <https://www.utilitydive.com/news/florida-regulators-hit-pause-on-utility-natural-gas-hedging-programs/429758/>

1 through December 2027, which was approved by Order PSC-2024-0472-AS-EI. Florida
2 Power and Light through settlement agreed to terminate 100% of any natural gas
3 financial hedging through December 2026, which was approved by Order PSC-2021-
4 0446-S-EI.

5 Similarly in South Carolina, Dominion Energy South Carolina was recently
6 required to evaluate the feasibility, costs, and benefits to customers associated with
7 reinstating a natural gas financial hedging program that had been suspended since
8 2012.¹²⁹ The results of the hedging examination were presented in DESC's 2024 fuel
9 proceeding, which recommended DESC continue its existing business practices of
10 natural/physical hedging, market purchases and implementation of customer bill rate
11 reset on an annual basis rather than expand its practices to include financial hedging.

12 **Q. PLEASE SUMMARIZE THE STAFF'S RECOMMENDATION REGARDING**
13 **THE COMPANY'S NATURAL GAS HEDGING PROGRAM.**

14 A. Staff recommends the natural gas hedging program be terminated as it is not necessary
15 for stable fuel rates for customers and will most likely increase ratepayers fuel cost in the
16 long run. The Company's natural gas hedging program has provided very little cost
17 stability and has cost customers considerably over the past twenty years. Fixed fuel rates
18 are by far a more efficient approach to providing fuel cost stability to customers at lower
19 cost. The Commission sets fixed fuel rates that do not change from month to month.
20 However, if the Commission were to allow the Company to continue, Staff recommends
21 that the Company be limited to hedging 30% of its projected burn volume and limited to
22 hedging 24 months in advance. Staff also recommends that the Company be required to

¹²⁹ Docket No. 2024-2-E— Order No. 2024-296.

1 file transaction level support for the annual hedging reports, which will provide
2 additional details and insight to the program's performance.

3 **Firm Transportation**

4 **Q. DOES THE COMPANY HAVE SIGNIFICANT ADDITIONAL NATURAL GAS**
5 **FIRM TRANSPORTATION COMING ONLINE DURING THE PROJECTED**
6 **PERIOD OF JUNE 2026 THROUGH MAY 2029?**

7 A. Yes. The Company will have an additional [REDACTED] MMBTU/day firm natural gas
8 transportation capacity coming online in late 2027.

9 **Q. WILL THE NEW FIRM TRANSPORTATION CAPACITY BE UTILIZED**
10 **DURING THE PROJECTED PERIOD.**

11 A. Not all of it. The Company has procured firm transportation from Transco for future
12 generation of new combined cycle units at Plants Bowen and Wansley.¹³⁰ The Company
13 will begin paying for the costs associated with these on [REDACTED] and estimated
14 the costs would be approximately \$[REDACTED] million during the projected period.

15 **Q. HAS THE COMPANY PROPOSED TO RECOVER THE COSTS ASSOCIATED**
16 **WITH THE ADDITIONAL NATURAL GAS FIRM TRANSPORTATION**
17 **THROUGH FUEL CLAUSE?**

18 A. Yes. However, the Company plans to monetize the firm transportation capacity and any
19 sale proceeds, in excess or shortfall of the capacity costs, will be credited to the fuel
20 clause to offset the capacity costs. If the Company is not able to monetize the additional
21 natural gas firm transportation not utilized for generation, the Company proposed that
22 "any capacity costs net of sale proceeds will be included in the fuel clause to be recovered

¹³⁰ Direct Testimony of Adam D. Houston and Matthew S. Berrigan, p. 19.

from, or returned to, customers.”¹³¹ These Company’s efforts and the ultimate costs to customers will be reviewed as part of the next FCR proceeding.

Interim Fuel Rider

Q. PLEASE DISCUSS THE INTERIM FUEL RECOVERY (“IFR”) MECHANISM.

A. The IFR mechanism was first approved in FCR-21, and its purpose has been to inform the Commission when the accumulation of a substantial over-recovered or under-recovered fuel balance occurs. The IFR provides the means by which Georgia Power can reset the FCR Tariff to address the fuel balance between FCR proceedings in an attempt to better align the costs customers pay with the actual costs the Company incurs. Prior to the Company filing FCR-26, the IFR mechanism rule limited any adjustment to no more than 15% above or below the approved FCR rates.

Beginning in about June 2021 when FCR-25 rates were in effect, the under-recovered fuel balance greatly increased as significant upward pressure on natural gas prices occurred. As a result, the Company implemented the maximum allowed 15% increase in the FCR-25 rates via the IFR-4 adjustment, which took effect in January 2022. Despite implementing the 15% increase in IFR-4, the Company’s FCR-25 under-recovered fuel balance continued to increase significantly through 2022.¹³² Because of this, the Company sought a change to the IFR mechanism in FCR-26, which allowed adjustments to be as much as 40% above or below the approved FCR rates, which the Commission approved.

Q. OVER THE FCR-27 HISTORICAL PERIOD HAS THE FUEL BALANCE

¹³¹ STF-JKA-3-34.

¹³² Direct Testimony of Sarah Adams and Adam Houston, Docket No. 44902, FCR-26, February 28, 2023, p. 13, l. 6.

EXCEEDED \$200 MILLION IN ANY HISTORICAL MONTH?

A. Yes, the cumulative Part-A fuel balance has exceeded \$200 million in eight months out of the historical period. In those eight months, the Company filed IFR reports as required; however, the Company did not seek to make a change in any of those months to the Part-A fuel rate to ensure the fuel balance would decline towards zero, which is the objective of the fuel cost recovery. Every month in which a balance exists, customers are required to pay the Company's carrying costs.

Q. DID THE COMPANY EXPLAIN WHY IT DID NOT SEEK AN ADJUSTMENT TO THE FCR RATES AS IT WAS PERMITTED TO DO?

A. The Company provided an explanation why it did not seek an adjustment in one out of eight IFR reports that it submitted since the completion of FCR-26, the very first one, which was associated with April 2025. The Company's explanation was,

The Company expects the recent decrease in natural gas prices, as evidenced by the latest natural gas forward price curve, to help mitigate and stabilize the under-recovered balance through the end of the current FCR period (May 2026). In addition, in the near term, volatility in the macroeconomy provides added uncertainty in these underrecovery projections.¹³³

While this may have been a reasonable explanation at the time, the Company offered no additional explanation why it did not seek an adjustment in any other IFR report that it filed during the FCR-27 historical period. As it turned out, the Company's expectations were wrong as the Company still had an under-recovered Part-A fuel balance that exceeded \$200 million through the end of December 2025. The under-recovered fuel balance would likely have been eliminated or significantly lower had an IFR been

¹³³ Georgia Power's IFR Report, filed in Docket No. 44902, May 14, 2025.

1 adopted.

2 **Q. PLEASE DESCRIBE THE CHANGES TO THE IFR MECHANISM THE**
3 **COMPANY HAS PROPOSED IN THIS PROCEEDING?**

4 A. The Company has proposed to increase the amount by which the Company can adjust
5 rates through the IFR mechanism from \$200 million to \$300 million, citing rate stability
6 and additional flexibility to timely address fuel price volatility as the reasons for the
7 proposed change.¹³⁴

8 **Q. DOES STAFF AGREE WITH THE COMPANY'S PROPOSAL?**

9 A. No. Staff understands rate stability is important; however, customers have to pay carrying
10 costs when the fuel balance grows and increasing to \$300 million could increase the
11 amount of carrying costs that will have to be paid. Furthermore, by not making fuel rate
12 changes using the IFR mechanism, the Company is pushing fuel costs to future
13 generations. Customers who did not incur the costs or benefit from the use of the fuel
14 will have to pay the under-recovered amounts. This is why an IFR is needed, to more
15 closely assign fuel costs to cost causers.

16 Staff disagrees with the Company and recommends the IFR remain unchanged at
17 the \$200 million threshold. Staff further recommends the Company not only be required
18 to make an informational filing but also be required to propose an adjustment to fuel rates
19 in an IFR filing to minimize cumulative impacts until a comprehensive fuel case can be
20 filed and reviewed. However, Staff proposes that IFR changes to fuel rates should occur
21 no more frequently than once every three months and should still be subject to the limit
22 that fuel rates should change by no more than 40% +/- since the last fuel proceeding.

¹³⁴ Direct Testimony of Adam Houston and Matthew Berrigan on behalf of Georgia Power Company, p. 22, l. 12.

1 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

2 **A. Yes it does.**

1 (The documents referred to were marked for
2 identification as PIA STAFF Exhibit 1.)

3 MR. COLLADO: And with your permission, the
4 panel would like to give a summary of their
5 testimony.

6 CHAIRMAN SHAW: Yes, sir. Y'all go ahead.

7 MR. NEWSOME: Good afternoon, Commissioners.
8 Our testimony addresses four Georgia Power requests
9 in this docket. These company requests are:

10 To set projected fuel rates to recover fuel
11 costs as projected for the company's FCR-27 test
12 period of June 26 through May 28.

13 To increase the threshold amount, which the
14 company can trigger a rate adjustment through the
15 Interim Fuel Rider from the current amount
16 200 million to 300 million.

17 To expand a natural gas hedging program.

18 And to authorize Georgia Power to recover all
19 renewable RFP, utility scale and distributed
20 generation, and renewable subscription
21 program-related costs, not otherwise recovered by
22 the company through bid fees and winner's fees, and
23 be recovered through the fuel clause.

24 Staff's primary recommendation -- excuse me.
25 Staff's primary recommendations are the following:

1 The company filed its next fuel case, FCR-28, in
2 February of '29 for new rates to go in effect
3 June 1st, 2029, on the traditional three-year
4 cycle.

5 The company should recompute the Part-B part.
6 Excuse me. The company should recompute the Part-B
7 part -- excuse me. The company should recompute
8 the Part-B rate to reflect a higher under-recovered
9 balance as of May 2026.

10 Staff recommends the IFR threshold remain at
11 200 million rather than change to 300 million,
12 recommended by Georgia Power. Staff also
13 recommends when the 200 million threshold is
14 exceeded, the company not only make an informal
15 filing, but be required to propose an adjustment to
16 fuel rates, though any changes should be limited to
17 occurring no more than once every three months.
18 Staff recommends a \$10 million disallowance for
19 excess costs from certain fossil fuel plant outages
20 during the historic period. Staff recommends the
21 company include natural gas firm transportation
22 costs and take-or-pay contract costs when
23 calculating the amount of RTP revenues credited to
24 fuel revenues.

25 Staff recommends that the Commission open an

1 investigation docket to consider if the RTF fuel
2 credit methodology and the company's application of
3 the methodology going forward is sufficient to
4 protect non-RTP customers from cost shifts
5 associated with future load growth.

6 Staff recommends the natural gas hedging
7 program be terminated, as is not necessary to
8 provide stable fuel rates for customers. The fuel
9 balance is the mechanism that provides stable fuel
10 rates, and hedging program is unnecessary and
11 redundant.

12 Staff recommends the company continue filing
13 semiannual fuel reports as it has in the past.
14 Additionally, staff recommends that hourly energy
15 and cost information be included to allow for
16 examination of Georgia Power's average fuel --
17 average hourly fuel costs and the amount of RTP
18 revenue credited to fuel revenues.

19 Staff recommends that certain administrative
20 costs for Georgia Power's renewable RFP and
21 renewable subscription programs be excluded from
22 recovery through the fuel clause. Any
23 administrative costs and excess revenue should be
24 placed in a regulatory asset and addressed in the
25 next base rate case.

1 Staff recommends the company explain in
2 rebuttal testimony its coal inventory management
3 strategy and provide evidence the coal units were
4 not operated uneconomically. Staff remains
5 concerned about this issue.

6 This concludes our summary.

7 MR. COLLADO: Mr. Chairman, the panel is
8 available for questions from the Commission.

9 CHAIRMAN SHAW: All right. That was quick,
10 quick summary of 77 pages.

11 MR. NEWSOME: I'm sure you appreciate it.

12 CHAIRMAN SHAW: Yeah.

13 All right. We'll move on. Commissioners,
14 any questions for this panel?

15 COMMISSIONER HUBBARD: So you mentioned the
16 uneconomic coal dispatch. Could you just expand on
17 that a little bit more and talk about what you saw
18 in the data?

19 MS. WELLBORN: Yes. So I think we addressed
20 this in the testimony around figure three on
21 page 25, a concern that coal inventories were not
22 on target and that there may have been uneconomic
23 dispatch.

24 Generally speaking, we asked DRs to assess
25 whether or not this behavior was driven by

1 operating constraints or economics. And we
2 received a number of DRs in which the company
3 explained that they've changed their methodology
4 and that the data is not easily available. Since
5 we filed testimony, there were some DRs provided,
6 JKA-71, and so I guess we still remain concerned is
7 our conclusion.

8 COMMISSIONER HUBBARD: Yes. Staff did -- you
9 did receive some data to help assess whether or not
10 you felt like this was -- the uneconomic dispatch
11 was transmission constrained or some other
12 constrained -- right? -- but were you able to feel
13 like you ran that to ground, or do you still need
14 some data to be able to assess that?

15 MS. WELLBORN: I think we can conclude that
16 there was inventory management happening. There
17 was some burns happening that were driven by
18 managing the coal pile. Whether that was
19 reasonable or the amount of, you know, uneconomic
20 dollars, we did not have the time to run down.

21 COMMISSIONER HUBBARD: Okay. But, yeah, but
22 it was mostly, in your view at least, fuel
23 management related rather than, say, transmission
24 constraints or something else?

25 MR. HAYET: Yeah. Well, we couldn't run to

1 the ground -- first, we were trying to figure out
2 was it indeed the fact that they -- they acquired
3 too much coal. And then one of the reasons for
4 acquiring too much coal, we have -- we weren't able
5 to run to ground.

6 But what we were trying to say is, if you did
7 acquire too much coal, you built up the stockpile
8 too high, then it becomes an issue that you got to
9 manage that stockpile. It could be dangerous. You
10 need to burn down the inventory, and that could be
11 an uneconomic situation.

12 So first we attempted to learn, did you
13 indeed burn uneconomically? We had a series of
14 discovery requests. We finally got to the point
15 where we got that answer. But to learn why the
16 coal stockpile grew so large, that's something that
17 we haven't been able to run to ground.

18 COMMISSIONER HUBBARD: And then I also saw in
19 your testimony that you had questions on where some
20 of the coal was coming from, whether it was
21 Northern Appalachian or Illinois Basin versus the
22 cheaper Powder River Basin. And I saw that you
23 had -- there was some back and forth on, well, you
24 can get PRB coal, but it'll have a lower heat
25 content. But that's accounted for in the cost

1 difference and the price difference. And so the
2 contention that sourcing coal from the PRB, you
3 just don't get as much capacity. You'd have to
4 derate some of your coal units. You wouldn't be
5 able to produce as much energy out of them
6 effectively, but --

7 MR. HAYET: It's actually slightly different
8 than that. It's not a question of Powder River
9 Basin versus Eastern Coal. It's a question of the
10 Eastern Coal regions. So there's Northern
11 Appalachian, Central Appalachian, and then there's
12 Illinois Basin. And the issue is that the company
13 wanted to diversify the coal supply on the Eastern
14 part of the country, and that's what's used at the
15 Bowen Plant.

16 And so it was a question for us of, well, you
17 can buy cheaper coal at some of the Eastern regions
18 than you were actually buying from. And why did
19 you make the decision to do that? And the company
20 explained it had to do with diversity reasons. But
21 it's still a question for us because, you know, the
22 company doesn't exactly have a policy other than --
23 other than saying we want to diversify the supply.

24 We understand that. I mean, it's a risk
25 mitigation sort of an answer, but it doesn't really

1 say how much are you willing to diversify the
2 supply and pay more money for, you know. What is
3 the differential that you're willing to pay, you
4 know? Can that be, you know, you know, \$10? Is it
5 a \$20? Is \$100 per ton. So it's still an open
6 question for us that we think that a policy should
7 be established, you know. And that's something
8 that the company does. So it's not something we
9 don't think is unusual for the company to do.

10 COMMISSIONER HUBBARD: Okay. Switching gears
11 a tiny bit, table 17, the winter peak hour
12 generation unavailable. This is on page 44. I'm
13 curious there. I see a number of units that are
14 there that had unavailability. Would you say
15 that -- is it true to say or fair to say that if
16 units are unavailable, then they're not able to
17 deliver 100 percent capacity availability? The
18 capacity accreditation of 100 percent might be
19 overshooting here?

20 MR. NEWSOME: If there -- can you repeat the
21 question?

22 COMMISSIONER HUBBARD: If there are
23 unforced -- if there are forced outages, unplanned
24 outages, is it fair to say that a unit is not
25 100 percent available and shouldn't have

1 100 percent accreditation for capacity?

2 MR. NEWSOME: Correct.

3 COMMISSIONER HUBBARD: Okay. All right. I
4 just wanted to check that, because I do see that
5 there's a number of units that haven't been fully
6 available. Okay. And that's -- yeah, I think, for
7 now I'm okay.

8 CHAIRMAN SHAW: All right. Any other
9 questions?

10 (No response.)

11 Moving on. Georgia Power.

12 MS. PRYOR: Chair, as the petitioner, we
13 would request to go last in our questions.

14 CHAIRMAN SHAW: All right. I'm sorry about
15 that.

16 Georgia Association of Manufacturers,
17 Mr. Jones.

18 MR. JONES: Thank you, Mr. Chairman. How are
19 you?

20 CHAIRMAN SHAW: Good.

21 MR. JONES: Good. How's the panel today?

22 THE PANEL: We're doing good.

23 CROSS-EXAMINATION

24 BY MR. JONES:

25 Q. I'll try not to say good morning, because

1 it's not good morning anymore. I'm Clay Jones on behalf
2 of the Georgia Association of Manufacturers, and I want to
3 ask you just a few questions today. I want to begin by
4 noting and getting you to agree with me, that staff and
5 GAM have some common issues of agreement in this case and
6 in the upcoming storm damages case. Would you agree with
7 me on that?

8 A. (Witness Newsome) Yes.

9 Q. And specifically in this case, both GAM and
10 staff express opposition to Georgia Power's proposal to
11 expand its hedging program, for example, agree?

12 A. (Witness Newsome) Yes.

13 Q. So I'm not going to focus on all areas of
14 your testimony. This is very thorough, but I did want to
15 talk about one area, which is your proposal to open an RTP
16 investigatory docket. Okay. And so that would be pages
17 55 to 64 of your testimony. I'm not going to have a whole
18 lot of questions about specific line numbers, but that's
19 the area of the testimony we'll be looking at. And I'm
20 going to direct my questions to the panel, and leave it to
21 you to determine who the best person is to respond, if
22 that works for you.

23 So let's start with your proposal. You
24 recommend that the Commission establish an investigatory
25 docket to reassess Georgia Power's method for quantifying

1 the marginal replacement cost of fuel; is that correct?

2 A. (Witness Newsome) Correct.

3 Q. Okay. And specifically you ask whether some
4 RTP revenues should be used to offset firm gas
5 transportation costs and certain take-or-pay fuel costs,
6 because your view is that RTP customers, I believe in your
7 testimony you say, relying on system capacity. Is that a
8 fair --

9 A. (Witness Newsome) Can you repeat the
10 question?

11 Q. So you ask whether some RTP revenues should
12 be used. Let me break up the question -- should be used
13 to offset firm gas transportation costs and certain
14 take-or-pay fuel costs; correct?

15 A. (Witness Newsome) I think we're saying
16 they're not including it when they go to calculate the
17 credit, so --

18 Q. Okay.

19 A. -- I think maybe you're saying the same
20 thing.

21 Q. They should be including it, is your
22 position?

23 A. (Witness Newsome) From what we've seen so
24 far, in the case, they may not be happening.

25 Q. Okay. And have you -- you reviewed Georgia

1 Power's written rebuttal testimony in the case?

2 A. (Witness Newsome) Yes.

3 Q. I know they haven't given it yet, but you've
4 read the prefiled testimony?

5 In that testimony they point out that -- that
6 they're using the same RTP fuel accounting methodology
7 that was approved in the 2010 base rate case. Do you
8 agree with me?

9 A. (Witness Newsome) True.

10 Q. And you agree that's what the company has
11 been doing or do you have any --

12 A. (Witness Newsome) I don't have it. That's
13 first time I've ever looked at it.

14 Q. Okay. And that current methodology
15 determines how much RTP revenues are accredited to fuel
16 cost recovery. Would you agree with that?

17 A. (Witness Newsome) Correct.

18 Q. Would you agree with me that a previously
19 approved ratemaking methodology can and should only be
20 changed in a base rate case?

21 A. (Witness Newsome) No, this affects fuel.

22 Q. Yeah.

23 A. It affects fuel, so that's why we're bringing
24 it up in a fuel case.

25 Q. Right. But to change the methodology, is

1 that -- the purpose of your investigatory docket is to
2 look into the issue; correct?

3 A. (Witness Newsome) To look into the credit,
4 the amount of revenues being credited to the fuel.

5 Q. Right.

6 A. (Witness Newsome) RTP revenues that are
7 being credited to the fuel. That's the extent of what we
8 want to look at.

9 Q. Okay. But it's an investigatory docket.
10 Would you be looking to change the methodology in that
11 docket, or do you believe that's --

12 A. (Witness Newsome) Depends on what we find --

13 Q. -- an appropriate issue or --
14 Go ahead.

15 A. (Witness Newsome) Okay. We're not.

16 Q. I don't want to cut you off.

17 A. (Witness Newsome) Okay. We may change how
18 the credit works. We do the investigation. We come up
19 recommendations, and they decide it needs to be changed.
20 It may not be that the methodology. It may be Georgia
21 Power, the application of the methodology. So maybe the
22 methodology is fine. The way they're applying, it may be
23 an issue.

24 Q. And are you asking in this investigatory
25 docket to potentially take action in that docket, or is it

1 investigatory docket that would set up potential changes
2 in the next rate case?

3 A. (Witness Newsome) No, it needs to be done.
4 This is for fuel. It needs to be done now.

5 Q. Okay.

6 A. (Witness Newsome) So, yeah, if we find
7 evidence, we think action should be taken, we'll make that
8 recommendation. The Commission can make a decision on it.

9 Q. Okay. Would you agree with me that any
10 change in a methodology like that should be applied
11 prospectively?

12 A. (Witness Newsome) Yes.

13 A. (Witness Hayet) Yeah.

14 Q. Okay. Not retroactively?

15 A. (Witness Newsome) No.

16 Q. The current methodology approved by the
17 Commission does not include firm transportation and
18 nondispatchable PPA costs in the RTP fuel credit
19 calculation. You just said that. And can I -- is it fair
20 to say that one of the reasons you are concerned about
21 this issue and recommend the docket is that you don't want
22 to see a shifting of costs to non-RTP customers as a
23 result of load growth?

24 A. (Witness Newsome) Yes.

25 Q. Okay. Now, to be clear, we've been talking a

1 lot today about RTP customers, and non-RTP customers, and
2 RTP customers, and non-RTP customers. But let's be clear,
3 RTP customers themselves also operate as non-RTP
4 customers; right?

5 A. (Witness Newsome) Right. The CBL.

6 Q. Right. Because a portion of their load,
7 correct, is their customer base load, or CBL, which
8 includes the FCR rates that are at issue in this docket;
9 right?

10 A. (Witness Newsome) Repeat the question.

11 Q. That CBL includes the FCR rate that is at
12 issue; correct?

13 A. (Witness Newsome) Correct.

14 Q. All right. So -- and -- but a portion of
15 their load is priced at the marginal cost of fuel in
16 real-time.

17 A. (Witness Newsome) It's an RTP.

18 Q. RTP. That's right. And that's -- those
19 customers take the -- take the risk of that in real-time,
20 so it's a different calculation.

21 A. (Witness Newsome) Oh, yeah.

22 Q. So a set rate like FCR, it varies; right?

23 A. (Witness Newsome) Right. I mean, they
24 signed up for it. They knew what they were getting into.

25 Q. Okay. So to support that concern about cost

1 shifting, I believe you produced a chart -- and I will
2 refer you to testimony here at the top of page 59. You're
3 probably there already. I know Tom is pretty quick. So
4 it's table 20, I believe.

5 And there are some trade secret numbers here,
6 so we don't want to mention specific numbers. This chart
7 shows that for the years selected, that marginal fuel
8 costs were below the average fuel cost; is that right?

9 A. (Witness Newsome) It shows -- go ahead.

10 A. (Witness Wellborn) I would say this is not
11 about the marginal cost paid by the RTP customers. I
12 think it's really important that we consider that the rate
13 that the customer pays is set based on the lambda and some
14 capacity and transmission and some risk adders, and that
15 is not what this table is showing. This is showing the
16 fuel credit portion.

17 And many of our recommendations that we've
18 offered here today are around the allocation and this RTP
19 fuel credit, so that we're matching the costs with the
20 appropriate revenues. We're not making proposals today to
21 change what the customer sees.

22 Q. I understand that, but I guess higher or
23 lower marginal fuel costs could affect and would affect
24 the RTP fuel credit; right?

25 A. (Witness Wellborn) Yes.

1 Q. Right. So it could make it higher or lower.
2 And in this chart, you're saying over the last three years
3 that the credit has been lower; is that --

4 A. (Witness Newsome) Correct.

5 Q. Than the average fuel costs. All right.

6 But since marginal -- but past performance
7 about fuel costs and the resulting credit, it's not a
8 guarantee of what the future will be; is that right?

9 A. (Witness Newsome) That's fair. But the one
10 concern I had myself is tables that delta. It's pretty
11 big.

12 Q. Uh-huh.

13 A. The RTP fuel credit is discounted quite a bit
14 against the actual cost to generate power, or the fuel
15 cost to generate power in those hours. So the fact that
16 there is a delta there is not the issue. It's the size of
17 the delta.

18 Q. Okay. But if marginal fuel costs, for
19 example, resulting in a higher RTP fuel credit, were
20 higher than average fuel cost, which they can be, you
21 would agree with me, they could be.

22 A. (Witness Newsome) Right.

23 Q. Right. So in 2022, for example, you can --
24 as indicated -- well, it's not in this chart because 2022
25 is not in this chart. But the RTP prices were very high

1 in 2022, do you recall that?

2 A. (Witness Newsome) Understood.

3 Q. Right.

4 A. (Witness Wellborn) Can I add --

5 Q. Either microphone is fine.

6 A. (Witness Wellborn) Again, I think your
7 statement that the RTP fuel price could be higher than the
8 average is correct. The price the customer sees could be
9 higher than the average. I think our issue here is the
10 RTP fuel credit methodology may not be structured that
11 way. And that's our proposal for the investigation, is to
12 understand whether or not certain aspects or certain
13 generation or certain costs, that are possibly being
14 recovered through the full RTP rate a customer pays,
15 should be allocated to the fuel.

16 Q. Okay.

17 A. (Witness Wellborn) But...

18 Q. I think I understand what you're saying, but,
19 again, we also agree that the credit can be impacted by
20 the marginal fuel costs as well?

21 A. (Witness Wellborn) The credit could be
22 impacted by, but the credit is based on an average of many
23 different fuel types. So it may also not be as impacted
24 as a straight marginal lambda. So it really is dependent
25 on the very specific methodology applied and the hourly

1 dispatch in every hour of the year.

2 Q. Okay.

3 A. (Witness Wellborn) Or three years.

4 Q. On page 61, lines three to four, you say that
5 RTP customers appear to rely on system capacity. And
6 would you agree that it's -- is what you're talking about
7 here your view is that RTP revenues are not specifically
8 credited against firm transportation costs, and it's not
9 clear to you how such costs are recognized in setting RTP
10 pricing?

11 A. (Witness Wellborn) Well, so, again, the RTP
12 price the customer pays has both a lambda sort of energy
13 price, and it also occasionally has a capacity price. And
14 so there are fixed prices components in what the RTP
15 customer pays. But what it does appear is that the fuel
16 credit methodology for that load does not appear to be
17 accounted for. Sorry. The FT costs are not a part of the
18 fuel credit methodology. The company admits that in the
19 rebuttal. So I think that is a conclusion that we're
20 making here.

21 Q. The question about firm transportation though
22 is, would you agree -- how would you characterize firm
23 transportation? Would you agree it's a system cost, not a
24 marginal cost? I mean, it's a fixed cost; right?

25 A. (Witness Newsome) Well, it can be variable

1 or fixed, depending on --

2 Q. Well --

3 A. (Witness Newsome) It can be variable or
4 fixed.

5 Q. Okay. But more specifically if Georgia
6 Power, if they dispatch more gas generation, they dispatch
7 less gas generation in general, it has very little impact,
8 if any, on the amount of firm transportation costs they
9 incur; right?

10 A. (Witness Newsome) We'll accept that, yeah.

11 Q. Yeah. So shippers pay to reserve a specific
12 amount of capacity, and they pay whether that capacity is
13 used or not?

14 A. (Witness Newsome) But you need that capacity
15 in order to serve those combined cycles.

16 Q. Right. Sure.

17 A. (Witness Newsome) And the RTP customers are
18 served by combined cycles.

19 MR. JONES: Okay. I think that's all I have
20 right now.

21 CHAIRMAN SHAW: Thank you, Mr. Jones.

22 Georgia Interfaith Power & Light and
23 Southface.

24 CROSS-EXAMINATION

25 BY MS. WHITFIELD:

1 Q. Good afternoon, panel.

2 A. [The Panel] Good afternoon.

3 Q. I'd like to start by asking you about your
4 Table 21 on page 62. As you just as established, the RTP
5 fuel credit is not providing any money towards paying for
6 firm transportation in the fuel docket; correct?

7 A. (Witness Wellborn) Yeah, that's our
8 understanding.

9 Q. And in this table, you quantify the total
10 amount of the firm transportation costs in the historic
11 period in column 1, correct?

12 A. Yes. We based -- I think, actually, the
13 Footnote 114. It's on MFRH 12. But we looked at the
14 historic costs for FTE over the last three years to sort
15 of look at what that fixed amount.

16 Q. And then you work on identifying the amount
17 of firm transportation that staff believes should be
18 credited or should be paid for by RTP, correct?

19 A. (Witness Wellborn) Yeah. So this is an
20 order-of-magnitude calculation looking at the peak hour
21 and whether or not RTP was, you know, being served in that
22 RTP or are they shedding their load and are truly
23 marginal.

24 So this is just an order of magnitude one
25 hour of the year, but it does show that it generally, for

1 the summer peak, there is an RTP utilization of the system
2 during the peak. And I'll add the company -- I think it
3 was in DRJK 314, you know, the company plans for RTP load
4 as per load. It's not, you know, this marginal load
5 that's sometimes included. It is considered a load of the
6 company.

7 And one reason we want the investigation is
8 to pin down these numbers.

9 Q. Okay. That's helpful.

10 And in terms of pinning down the number you
11 were just describing, Ms. Wellborn, the percentage of the
12 total firm transportation cost that staff proposes here is
13 one method of allocating those costs to RTP customers, but
14 are there other equally valid methods of allocating cost
15 of firm transportation that could be investigated and
16 should be investigated in an RTP study docket, like on an
17 energy basis, as used for the rest of the FCR docket?

18 A. (Witness Wellborn) Yes. I think the
19 investigation could consider the appropriate allocation
20 methodology.

21 This was supposed to be indicative of sort of
22 what this looks like in the summer. You might want to
23 look at the top 50 peak hours that the company is sort of
24 using for when -- the charge on the capacity component.
25 You might want to look at energy. You might want to look

1 at in the winter. So -- but this is an order of magnitude
2 sort of starting point on -- on -- this is not a
3 \$1 million issue. This is bigger than a \$1 million issue.

4 Q. Right. And you are recommending that this
5 Commission take steps to prevent this cross-subsidization
6 of -- by non-RTP customers for RTP customers in the
7 future, but you're not recommending that they take steps
8 to remove these dollars from what everyone else has to pay
9 right now. Why is that?

10 A. (Witness Wellborn) I think we've
11 acknowledged that the company is relying on the 2010 rate
12 case, and that -- the specific language in that rate case
13 for the methodology. Now, I think the methodology was --
14 was broad and in terms of what was approved. But this is
15 a growing issue. So it's definitely something we're
16 flagging for now and for the future.

17 Q. Okay. And by not recommending it here, that
18 doesn't mean that staff is agreeing with Georgia Power's
19 proposal that all of the new firm transportation for the
20 newly built generation at Wansley, Bowen and Yates be paid
21 for by non-RTP customers; correct? That is something you
22 want to investigate?

23 A. (Witness Newsome) Yeah. We need to -- we
24 would investigate it.

1 Q. Okay. Turning to page 59, Table 20, you just
2 talked about this table with GAM. Could you just help me
3 understand. You -- you described the delta as being very
4 large. And clearly this second line here is the RTP fuel
5 credit, which is the amount of money that RTP contributes
6 in this fuel docket.

7 What is that first column, and how did you
8 calculate that first column of fuel cost?

9 A. (Witness Wellborn) Oh, the first row. The
10 cost apply?

11 Q. Yes, the first row. Thank you.

12 A. (Witness Wellborn) So that is derived based
13 on the company's MFRH sort of total supply cost. And then
14 the net of, I think, one oh -- 1016 as -- we took out
15 hedging carrying costs, sort of those line items at the
16 bottom.

17 Q. Uh-huh.

18 A. (Witness Wellborn) If you look at our
19 Exhibit 5 or -- our Exhibit 5, you can kind of see the
20 items that would go into, like, a total FCR cost, and then
21 you can sort of see some adjustments and some revenues.
22 And what we're really trying to do there is just look at
23 everything that goes in as an FCR dollar, and then the
24 megawatt hours that are associated with those dollars.

25 Q. Okay.

1 A. (Witness Newsome) I was going to say that
2 that first row is just the cost, the fire, the generators,
3 the fuel cost to run the generators in that hour. That's
4 it. We're not including in the FTE to do it. But, again,
5 as the footnote says, we don't have any hedging in there.
6 It's a carrying cost. It's the cost of fuel to run those
7 generators in that hour.

8 Q. So am I correct, then, in understanding that
9 if you were to include all of the costs that non-RTP
10 customers pay for fuel, that delta would be higher?

11 A. (Witness Newsome) Yes. But we exclude the
12 hedging and carrying cost because our RT -- RTP customers
13 failing -- they're not causing an under/over recovery.
14 They pay as they go. So they're not -- they're not
15 causing any of the carrying costs.

16 And it's kind of the same philosophy on the
17 hedging too. They're paying as they go and so we didn't
18 include it in there. We're trying to -- we're trying to
19 make it into a conservative.

20 Q. Yep. Understood.

21 So about carrying costs. You mentioned that
22 RTP customers aren't causing an over or under recovery,
23 but if Georgia Power maintains the position that it
24 appears to have from its document responses, that it is,
25 in fact, charging RTP customers for some of the fixed

1 costs in the fuel docket, like firm transportation, it's
2 just that those dollars aren't showing up.

3 If they maintain that position, would staff
4 be open to not charging carrying costs for everyone else
5 for the money that Georgia Power is collecting in real
6 time, just not accounting for here.

7 A. (Witness Newsome) You need to rephrase that.
8 Just repeat that question. You had a lot in there.

9 Q. Okay. Assuming it -- I'll get right to the
10 heart of it.

11 Is staff open to considering whether carrying
12 costs should be on the table in the study docket as to how
13 accounting is done, in light of the fact that Georgia
14 Power appears to be collecting costs that it is designed
15 to recover for fuel, that it is not showing up in the fuel
16 docket?

17 A. (Witness Newsome) Oh, our term -- thinking
18 investigative docket. We're not looking at carrying cost.
19 We're just looking at the fuel, RTP fuel credit for fuel.
20 So we wouldn't be looking at the carrying cost.

21 A. (Witness Wellborn) But I would say I think
22 our recommendation is in an acknowledgment that we would
23 like them to match; right? If we see the FT costs in the
24 fuel, we'd like to see revenues in the fuel. So, yeah, I
25 think I'd echo, you know, carrying costs, not really

1 fundamental to that point. That's really where our
2 concern is.

3 Q. It's helpful. Thank you.

4 And turning to page 4, Table 1, here you have
5 a table that summarizes values for various issues that you
6 raised throughout your testimony. But I want to highlight
7 specifically the last column, which is the take-or-pay
8 column. And that's referring to take-or-pay contracts for
9 coal. Correct?

10 A. (Witness Newsome) No.

11 A. (Witness Wellborn) It's not necessarily
12 coal. That's more on the RTP fuel credit for contracts
13 that are not considered dispatchable, but have a cost.

14 Q. Okay. And in light of the document response
15 that came in that you referenced, that document response
16 is pending, has staff come up with a recommendation and/or
17 a calculation for that particular line item?

18 A. (Witness Wellborn) Oh, no. Okay. Sorry.
19 Are you talking about uneconomic coal? Are you talking
20 about take-or-pay like --

21 Q. Take-or-pay. That particular column, there's
22 a -- there's a footnote there that says, essentially, it's
23 pending more information from Georgia Power in a document
24 response. So I'm wondering if you have that information
25 and if that's led to more --

1 A. (Witness Wellborn) We do. So in 61, the
2 company provided a listing of many of the contracts and
3 generators and components of its fleet and whether or not
4 those components can set lambda and whether those
5 components can -- let me think.

6 It did sort of break it down into four
7 categories, where you could be a yes/no on whether you set
8 lambda and a yes/no one whether you would be in sort of
9 the fuel credit.

10 And so we do understand broadly what
11 categories are in the methodology. What is, I think,
12 still pending is the magnitude of the dollars, the
13 magnitude of the energy, and just the general rationale
14 that we're -- we're after in this RTP investigation on,
15 like, are there nuances between what is a Georgia Power
16 unit that's considered nondispatchable or a -- you know, a
17 QF versus a solar PPA, like, we -- we would like to see
18 that level of granularity, because there may be some
19 nuance on this sort of take-or-pay dispatchable
20 methodology.

21 A. (Witness Newsome) Go ahead.

22 A. (Witness Hayet) And I would just add very
23 quickly that -- that just as Georgia Power's witnesses
24 earlier stated, it's very complicated. So it takes a
25 number of discovery requests to get the information. But

1 you have to get to the granular level and try and
2 understand it all. So that that's what I would add to
3 that.

4 A. (Witness Newsome) I would just say on that
5 RTP fuel credit, take-or-pay, it's going into FCR bucket.
6 The FCR customer is getting charged it, well, then the RTP
7 customer will get it charged too, because when they give
8 an hour, take-or-pay, they had to produce energy, so that
9 RTP should get their share of it too. That's kind of the
10 fundamental issue with it.

11 Q. And based on the document response that you
12 subsequently reviewed, were you able to determine if the
13 RTP fuel credit included reimbursement for those
14 particular items?

15 A. (Witness Newsome) I believe the answer is
16 no, but --

17 Q. Not yet.

18 A. (Witness Wellborn) Yeah. I would say it's
19 still pending, but our general understanding from the
20 narrative responses is that there are some take-or-pay
21 contracts that are not in that methodology, and I think
22 that is supported by the company's testimony.

23 Q. And, Ms. Wellborn, leaning into how
24 complicated this particular issue becomes, you referenced
25 lambda as one bucket, and that is a price metric for RTP

1 customers, and you also mentioned the fuel credit as
2 another metric, which is what shows up in the fuel docket
3 from RTP customers. But can you help me understand, if
4 you know today, what is the difference between that fuel
5 credit and lambda? What -- what falls in that margin?

6 A. (Witness Wellborn) I would say, broadly
7 based on the historic data, so there may be months where
8 this is not true, but generally speaking, the RTP fuel
9 credit is the smallest, most granular amount of rate we
10 see.

11 And then above that we would see something
12 closer to the average fuel cost or the lambda, depending
13 on the -- the month. And then above that would be what
14 the RTP customer pays, because the RTP customer is paying
15 even more than lambda. They're paying lambda with
16 capacity, with transmission, with risk adder.

17 And so it's sort of the stair step of, well,
18 which metric are you using when? Which metric is most
19 appropriate when? But if your question, I think, was how
20 does lambda compare to the RTP fuel credit, for the last
21 three years it is about the same, if not bigger, than the
22 difference between the average fuel supply cost in the RTP
23 credit. So it is about that.

24 MS. WHITFIELD: Thank you. Nothing further.

25 CHAIRMAN SHAW: MARTA.

1 CROSS-EXAMINATION

2 BY MR. BAKER:

3 Q. Good afternoon, panel. Robert Baker, I
4 represent the Metropolitan Atlanta Rapid Transit
5 Authority. A few questions for you on your prefiled
6 testimony. Referring to page 10, line 9, is it still your
7 belief today that the remaining Part-B balance will be
8 paid off by May 31st, 2026?

9 A. (Witness Newsome) Based on the company's
10 filings, yes.

11 Q. And would you say that it's fair to say that
12 natural gas volatility is predictable based on weather and
13 the time of the year, as a general proposition?

14 A. (Witness Newsome) Repeat that question.

15 Q. Referring -- well, is it fair to say that
16 natural gas volatility is predictable based on weather and
17 the time of the year?

18 A. (Witness Newsome) There's probably some
19 correlation, but I don't know if you can say it's
20 predictable.

21 A. (Witness Sandonato) And I would add a little
22 bit to that as well that, yeah, there may be some
23 correlations that go with that, but there's so many
24 geopolitical impacts that that could impact pricing as
25 well as, you know, any other extreme weather events that

1 could go into it. So while there could be trends, I don't
2 think it's inherently easy to predict the volatility of
3 natural gas pricing.

4 Q. Well, in your testimony in your chart, were
5 most of the spikes for natural gas in the winter in
6 January and February months?

7 A. (Witness Sandonato) They were, yes.

8 A. (Witness Newsome) Yeah. But like we'll go
9 back to the correlation issue, that one of the biggest
10 spikes was, what, winter '22. Maybe it wasn't necessarily
11 the winter, it was the Russian invasion of Ukraine. So
12 can be different things that make it happen. It's just
13 not weather, but weather is certainly a driver of it.

14 Q. And in your prefiled testimony you state that
15 the company has lost \$753 million during a 2006 through
16 2025 period. Does the \$753 million in hedge losses
17 include the carrying cost charged for those fuel costs?

18 A. (Witness Newsome) No, it's just a hedging
19 cost, separate. Carrying cost is separate from hedging
20 costs. So it's just hedging cost.

21 Q. Okay. But there are carrying costs that
22 would be incurred by customers for the --

23 A. (Witness Newsome) Right. It was just
24 embedded in the fuel balance is what happened.

25 Q. Okay. And would you agree that fuel costs

1 are included in a customer's monthly bill?

2 A. (Witness Newsome) Oh, yeah. Yes.

3 Q. Okay. And isn't sales tax charged, based on
4 the customer's total bill, which includes fuel cost?

5 A. (Witness Newsome) Yes.

6 Q. And additionally, aren't all riders, the
7 ECCR, the DSM and MFF, charged to a customer calculated
8 based on the total amount of the monthly bill?

9 A. (Witness Newsome) Yeah. The base part of
10 the bill, yes.

11 Q. And the base part of the bill. It does
12 include fuel cost?

13 A. (Witness Newsome) I'm not quite sure. I know
14 those -- the ECCR MFR, DSM, their percentage, my
15 understanding, is of the base. It doesn't include the
16 fuel.

17 Q. Right.

18 A. (Witness Newsome) But that's kind of a
19 substantive check. So I'm not totally sure on that.

20 Q. All right.

21 A. (Witness Newsome) But I think that fuel's
22 just separated out. I think the sales tax is -- they get
23 everything in there, and then they tack the sales tax on,
24 and then you get your final bill.

25 Q. So you are sure that the carrying cost for

1 fuel and the sales tax that a customer pays would cover
2 all fuel costs, including the embedded hedging cost for
3 fuel?

4 A. (Witness Newsome) Yeah, the hedging cost is
5 included in the fuel cost. That's covered.

6 Q. Okay. And don't you think you need to
7 include or factor in all the additional expenses of sales
8 tax and hedging costs when determining the amount of the
9 financial impact on customers of the hedging program?

10 A. (Witness Newsome) I mean, that's fair, but I
11 mean, we -- I mean, you could, yes.

12 A. (Witness Hayet) And I think it made the
13 point that we were trying to achieve.

14 Q. But there -- the point I'm trying to make is,
15 are there some additional costs that might also be --

16 A. (Witness Newsome) Right.

17 A. (Witness Hayet) Yeah.

18 Q. So it might be higher than \$753 million?

19 A. (Witness Newsome) That's fair.

20 MR. BAKER: Okay. Thank you very much.

21 CHAIRMAN SHAW: Resource Supply Management.

22 (No response.)

23 Sierra Club, SACE, NRDC.

24 CROSS-EXAMINATION

25

1 BY MS. ARIZA:

2 Q. Thank you. Good afternoon, panel.

3 A. (Witness Hayet) Good afternoon.

4 A. (Witness Newsome) Good afternoon.

5 Q. For the record, I'm Isabella Ariza, and I
6 represent Sierra Club, SACE, and NRDC in this proceeding.

7 You conducted an investigation of the
8 company's coal procurement activities that you describe on
9 pages 27 through 33 of your direct testimony. To
10 summarize, that analysis shows that the company's
11 repetitive practice has been to purchase more expensive
12 coal when other cheaper options were available; is that
13 generally correct?

14 A. (Witness Newsome) That's correct, but
15 there's a reason for that diversity, what have you.

16 Q. Okay. And I will ask the company for the
17 reasons behind that and whether diversity is adequately
18 justified. But in your testimony, you don't ask the
19 Commission to disallow any particular amount attached to
20 that behavior; right?

21 A. (Witness Newsome) Correct. But just --
22 conceptually, we agree with what the company is doing in
23 terms of trying to diversify the supply of stuff out, you
24 know, have more suppliers in different regions. That
25 part's okay. The question of the details is how much of

1 it do you do? You know, I think we brought that out in
2 the testimony there. So that's a bit subjective.

3 And we probably -- I think Mr. Hayet pointed
4 out they probably need to have some kind of more -- I
5 mean, they kind of -- it's kind of on an ad hoc basis now.
6 That's our understanding, more of -- a bit more formal
7 policy to help us, that would be helpful.

8 Q. And is that because --

9 A. (Witness Hayet) I would agree with you, I
10 think.

11 Q. Okay. Do you believe that this behavior
12 without a policy is problematic and something that the
13 Commission should look into?

14 A. Yes. But I think the way we've left it, we
15 need the company to let them take a shot at it and put
16 some parameters on it and some, you know, some kind of
17 framework around it. And then we would probably, you
18 know, look at that, then -- and then maybe if we're not
19 happy, or we don't think it's sufficient, then we -- it
20 gets escalated. But I think it's something the company
21 can do, handle right now, yes.

22 Q. Okay. And as the company plans to burn more
23 coal over the next few years, is it fair to say that the
24 risks that you lay out with this practice will increase
25 and have a potentially bigger impact on the companies and

1 ratepayers?

2 A. (Witness Newsome) It could, yeah. I mean,
3 they may be burning -- yeah, if they get burn more coal,
4 they get more coal from -- that's less economic, so, yes.

5 A. (Witness Hayet) You know, we have to
6 recognize the company made a commitment to purchase a
7 certain amount of coal looking -- moving -- going forward,
8 and that's what this is about. So for the next few years,
9 it entered into these contracts. We understand this, but
10 there's longer term into the future, the company may
11 continue to do this practice. And we think that their
12 policies should be addressed so that we know what the
13 limits are and what the extent of the delta may be and
14 what the volume should be, and is that reasonable.

15 A. (Witness Wellborn) Okay. I might add on
16 page 31, and it's trade secret, so I won't say the
17 specifics. But that line six, there's discussion of why
18 the diversity might help. And I think what our position
19 is looking between that and table 12 is that it could be
20 reconciled is how they're applying that parameter to what
21 they're doing in table 12, is that reasonable?

22 MS. ARIZA: Okay. Thank you. No further
23 questions.

24 VICE-CHAIRMAN MCDONALD: Redirect?

25 I mean, Georgia Power. Excuse me. Same

1 group.

2 MS. PRYOR: Thank you.

3 CROSS-EXAMINATION

4 BY MS. PRYOR:

5 Q. Allison Pryor on behalf of Georgia Power
6 Company. Good to see you, Panel.

7 When you took the stand, Commissioner Hubbard
8 asked you a question about table 17 and certain units that
9 were unavailable.

10 A. (Witness Newsome) You got a page number on
11 that?

12 A. (Witness Wellborn) 44.

13 A. (Witness Newsome) We've got it. 44.

14 Q. You'd agree that table 17 is -- only
15 specifies the units that were unavailable in the single
16 winter peak hour; correct?

17 A. (Witness Wellborn) Yes.

18 Q. And there's no indication in that table that
19 those units were not available in the hour following that
20 peak hour; correct?

21 A. (Witness Wellborn) That's true. So table 17
22 lines up exactly to table 16, and so it's that hour. And
23 it's just sort of breaking down what's happening in that
24 peak hour by resource --

25 A. (Witness Newsome) I was pointing out maybe

1 they were available, maybe they weren't, we don't know.

2 Q. Right. But the table itself was just
3 regarding the single peak hour; correct?

4 A. (Witness Newsome) Yeah, but that's the
5 important hour.

6 Q. Right.

7 A. (Witness Newsome) That's the reason we build
8 those capacities available on peak.

9 Q. Regarding staff's recommendations related to
10 the IFR, staff has proposed that in each IFR filing made
11 by the company, Georgia Power be required to propose an
12 adjustment to fuel rates, rather than just make an
13 informational filing; is that correct?

14 A. (Witness Newsome) Correct.

15 Q. And is it staff's position that the company
16 should be required to propose a change in fuel rates, even
17 if the company itself believes one is not necessary?

18 A. (Witness Hayet) The company believes at
19 least six times it was unnecessary in 2025, and there were
20 even more times in 2026. So apparently the company may
21 not have been correct in projecting forward thinking that
22 that the balance was going to decline. So, yes, we
23 believe that if they're going to -- we believe that there
24 should be an adjustment. We believe the company should
25 request an adjustment, and that's something that the

1 Commission can decide.

2 Q. Is it staff's recommendation that more
3 frequent rate adjustments are beneficial to customers?

4 A. (Witness Newsome) If you could lower your
5 carrying cost, yeah, potentially.

6 Q. Does the existing FCR and IFR framework
7 prohibit staff from raising concerns regarding the fuel
8 balance or requesting that the Commission order the
9 company to adjust fuel rates?

10 A. (Witness Newsome) Repeat the question.

11 Q. Does the existing FCR and IFR framework
12 prohibit staff from raising concerns regarding the fuel
13 balance, or requesting that the Commission order the
14 company to adjust fuel rates?

15 A. (Witness Newsome) I'm going to say no.

16 Q. Is staff aware that the current 200 million
17 threshold for triggering an IFR is approximately 6 percent
18 of the annual fuel cost during the test period?

19 A. (Witness Newsome) Sure, yeah.

20 Q. Do you agree that adjusting rates every -- no
21 more frequently than every quarter, as staff has proposed,
22 may impact the ability of manufacturing facilities to
23 budget for their electric bills?

24 A. (Witness Newsome) Repeat the question.

25 Q. Do you agree that adjusting rates no more

1 than every quarter, so for an IFR, I believe you've
2 recommended that they not change more than --

3 A. (Witness Newsome) Correct.

4 Q. -- once a quarter; correct?

5 A. (Witness Newsome) Correct.

6 Q. Do you agree that if it -- that adjusting
7 rates every quarter may impact the ability of
8 manufacturing facilities to budget for their electric
9 bills?

10 A. (Witness Newsome) Well, you're making an
11 assumption they're about to be adjusted every quarter. So
12 I don't -- I mean, we put the quarter in there -- or if
13 it's actually three months, to prevent frequent changes.
14 And that was the whole point of it, to prevent frequent
15 changes.

16 Q. Can you turn to page 23 of your testimony?
17 Looking there at line 1, you reference the company's green
18 energy riders. Do you see that?

19 A. Yeah.

20 Q. And are you aware that Georgia Power does not
21 currently have a green energy tariff?

22 A. I mean, you've got a lot of different
23 tariffs, but I don't know specifically green energy.

24 Q. Okay. Beginning on line 3, you outline the
25 company's renewable customer programs, the revenues from

1 which offset the cost of purchasing, purchasing renewable
2 energy; correct?

3 A. (Witness Newsome) Correct.

4 Q. Okay. Are you aware that none of the
5 projects in the ASI portfolios are supplying any of the
6 renewable subscriptions made available to customers?

7 A. (Witness Wellborn) Can you repeat the
8 question?

9 Q. Sure. Are you aware that none of the
10 projects in the ASI portfolio are supplying subscriptions
11 via a customer renewable program?

12 A. (Witness Wellborn) Yeah, I don't think we
13 have a specific reconciliation. One of our
14 recommendations was to get a program line item,
15 reconciliation of the costs of the historic period to
16 match to the projected, so we can sort of see which
17 components are in which program and what types of costs
18 are in there. And I believe the company gave us that DR
19 75, but I don't think we have it in front of us.

20 Q. Okay. So you're not aware, then, that the
21 references in lines five and six to the green energy
22 program R&R, solar purchase, etc., none of those are
23 either active, they no longer exist, or supply any of the
24 customer renewable programs?

25 A. (Witness Wellborn) I'm not sure we're

1 talking about -- I think these are different lines that
2 have been in the FCR before, but whether they're still
3 current active subscriptions, I don't think we have that
4 data.

5 A. (Witness Hayet) Nor was that our
6 intention --

7 Q. Okay. So you're just mentioning prior
8 programs that may have previously been in existence.

9 A. (Witness Hayet) Right.

10 Q. Does staff agree that the renewable energy
11 procured through renewable RFPs offsets fuel purchases
12 from other sources, such as coal and natural gas?

13 A. (Witness Newsome) At a certain cost, yes.

14 Q. And do you agree that the benefits of the
15 renewable PPAs show up in the FCR?

16 A. (Witness Newsome) What do you mean by the
17 benefit? I mean, the cost shows up in the FCR. I don't
18 know what -- when you say the benefit --

19 Q. Well, the revenues from running those RFPs
20 and offering renewal programs also appear in FCR too;
21 correct?

22 A. (Witness Newsome) Right.

23 Q. And staff appreciates the nuance that
24 renewable RFP-related costs and revenues differ from the
25 costs and revenues from the renewable subscription

1 programs; right?

2 A. (Witness Wellborn) Yes. Yes. The RFP costs
3 have been separately itemized as a component of the
4 overall program budgets.

5 Q. Okay. And beginning on page 23, line 13, you
6 identify 49.3 million in revenues from renewable RFPs. Do
7 you see that? This is during the historic period.

8 A. (Witness Wellborn) Yes. It's on the
9 company's response to JK 229.

10 Q. And you also note that throughout the
11 historic period, there were only 27.9 million in
12 RFP-related expenses; correct?

13 A. (Witness Wellborn) I think that's what row
14 15 says.

15 Q. So when the RFP-related revenues are netted
16 against the cost during the historic period, customers
17 benefited from 21.4 million that was credited to the fuel
18 balance as a result of these procurements; correct?

19 A. (Witness Wellborn) I think if you're asking
20 if the revenues exceeded the costs, possibly. But I think
21 what our concern is, was more based on both components.
22 We've got this RFP component, which in the company's
23 original filing showed a net cost on a projected basis.
24 And it has been corrected now via the errata. But that
25 was one concern, is that the RFP component pieces were not

1 matching.

2 And then we have this other concern, which is
3 even though the company's saying that because these
4 renewable energy benefits are flowing through FCR, the
5 labor associated with renewable programs would flow
6 through FCR. I think that's a little bit of a gray area
7 that we've flagged for a rate case, because it's still a
8 labor cost that's fixed and knowable and unchanging year
9 over year. And so that's -- I don't want to muddy the two
10 arguments. They're related, certainly, but those are our
11 concerns is that RFP costs should be set in such a way --
12 or the program revenues from those RFP revenues should
13 offset the cost of the RFP. That would be the ideal
14 situation. And we also want to see how fixed labor costs
15 for renewable operations, program operations, eventually
16 migrate over to base rates would be ideal.

17 A. (Witness Hayet) And to add to what my
18 colleague just said, I recall hearing the company say
19 earlier today that the costs associated with the renewable
20 program, such as labor cost, because it's a -- they
21 attributed it, the RFP cost, as a fuel-related cost, but
22 it's a renewable program. It's the running of the program
23 through the RFP. And I couldn't help but think that,
24 well, there are capacity RFPs as well that incur labor
25 costs. But those costs run through base rates.

1 So for that reason, I'm not quite sure why a
2 labor cost that's associated with a renewable program is
3 necessarily -- should be considered a fuel cost, while the
4 same labor costs associated with a -- with a capacity RFP
5 should run through base rates.

6 A. (Witness Newsome) Fossil capacity RFP.

7 A. (Witness Hayet) That's right.

8 A. (Witness Newsome) Fossil.

9 Q. And so I know you just mentioned the table.
10 I believe it was table 19, that would have been revised
11 based off the errata that the company filed last week;
12 correct?

13 A. (Witness Wellborn) That's correct.

14 Q. And did you have an opportunity to change any
15 of those numbers or review the impact of the errata on
16 that table?

17 A. (Witness Wellborn) I did.

18 Q. Okay. Good. I believe Mr. Newsome, in his
19 summation, mentioned that the recommendations wouldn't
20 have changed, but the numbers would have; is that correct?

21 A. (Witness Newsome) Correct.

22 Q. Okay. Do you agree that based on the data
23 filed in the company's errata, that the projected
24 RFP-related revenues now exceed the costs for the test
25 period?

1 A. (Witness Wellborn) That's the projection.

2 Q. And does staff agree that only the actual
3 costs and revenues related to the RFP would go through
4 fuel, if they were continue to allow to flow through that
5 mechanism?

6 A. (Witness Wellborn) Yes.

7 Q. And currently, Georgia Power recovers all
8 renewable RFP-related costs and revenues through fuel;
9 correct?

10 A. (Witness Wellborn) I have a hard time with
11 "all," but I -- but there are many types of program costs
12 and expenses going through the FCR, and I think it is a
13 majority.

14 Q. Okay. And the same would be true for the
15 majority of the company's renewable customer programs;
16 correct?

17 A. (Witness Wellborn) Subject to check.

18 Q. And I believe one of your recommendations
19 related to the renewable RFP side of things was that the
20 RFP fees should be set to recover the cost to run the RFP;
21 is that correct?

22 A. (Witness Wellborn) Yes.

23 Q. Okay. But there's a trade-off in setting RFP
24 fees; correct? That Georgia Power wants to set the RFP
25 high enough to cover the company's costs of running the

1 RFP without setting them so high that they discourage
2 participation; correct?

3 A. (Witness Wellborn) I understand those types
4 of considerations are considered when those RFPs are run
5 and approved. We're not refuting maybe some of the
6 rationale, but we understand that in previous agreements
7 and settlement that there has been discussion that they
8 would be targeted to make that cost and that revenue
9 equate. And that's an expectation we think is important
10 to make sure that the programs aren't -- the net costs
11 flowing over into other areas.

12 Q. And staff would agree that the appropriate
13 balance there is a policy commission -- a policy decision
14 of the Commission; correct?

15 A. (Witness Newsome) Yes.

16 Q. And just to clarify, staff's recommendation,
17 as it relates to this, staff recommends that the projected
18 costs in excess of revenues with Georgia Power's renewable
19 RFPs and renewable subscription programs be excluded from
20 the recovery through the fuel clause; is that right?

21 A. (Witness Newsome) Repeat the question.

22 Q. Staff recommends that the projected costs in
23 excess of revenues related to Georgia Power's renewable
24 RFPs and renewable customer programs be excluded from
25 recovery from the fuel clause; is that right?

1 A. (Witness Newsome) Yes. But also putting the
2 regulatory asset so the company gets recovery.

3 Q. And that would be a change to how they're
4 currently recovered; correct?

5 A. (Witness Newsome) Yes.

6 Q. Okay. And so to the extent -- so just --
7 again, to clarify, to the extent that the renewable RFP
8 and program-related costs offset, staff is okay with those
9 still going through fuel, just the excess being placed in
10 a regulatory --

11 A. (Witness Newsome) Correct.

12 Q. -- asset?

13 A. (Witness Newsome) This is kind of the -- I'm
14 sorry.

15 Q. No, go ahead.

16 A. What we came up with was kind of a
17 middle-of-the-road position. What we wanted to say was
18 kick it all out, take out all the base rates.

19 Q. So that's not your recommendation? You're --

20 A. (Witness Newsome) No, that's not the
21 recommendation. But if y'all are irritated with this, we
22 had actually a worse one for you. But -- so we figured we
23 would need to make you guys whole on the cost. We
24 couldn't just say, they don't get recovery. So we're not
25 going to allow you to run it through fuel. We said, hey,

1 put it in regulatory asset, and then go to recovering base
2 rates, so...

3 Q. So would the same be true if revenues
4 exceeded costs? Would you want those revenues to be set
5 aside in a regulatory liability?

6 A. (Witness Newsome) Probably so. I mean, if
7 we're going to do it one way, we've got to do it the
8 other.

9 Q. Turning now to a couple of questions on firm
10 transportation. Firm transportation costs are fixed fuel
11 costs; correct?

12 A. (Witness Wellborn) Generally, yes.

13 A. (Witness Newsome) My understanding it's both
14 a variable and a fixed component. We're talking about
15 natural gas; right?

16 Q. Yes.

17 A. (Witness Newsome) Okay. Natural gas, firm
18 transportation. My understanding is there's both a fixed
19 and a variable component.

20 Q. But firm transportation costs, once procured,
21 don't vary daily or hourly, do they?

22 A. (Witness Sandonato) And this is specifically
23 that you're asking for firm transportation, not for fixed
24 transportation, natural gas costs, associated with storage
25 or other services, just firm transportation?

1 Q. Firm transportation.

2 A. (Witness Sandonato) Yes. They're fixed.

3 Q. Okay. And once procured, the firm
4 transportation costs, or the amount needed, is not
5 dependent on peak periods; correct?

6 A. (Witness Sandonato) Correct.

7 A. (Witness Wellborn) Though, I will say I
8 think the idea is the company is procuring enough to be
9 able to fully serve its load in peak periods. So to the
10 extent it doesn't fluctuate, that's correct. But it is
11 procured to survey peak.

12 Q. Understood. On page 24, lines four through
13 eight. I'm moving now to your review of the company's --
14 to the coal review that you did. On lines four through
15 eight, page 24, staff references a requirement to meet
16 specific coal inventory targets; correct?

17 A. (Witness Hayet) Yes.

18 Q. And the inventory target ranges refer to the
19 days' worth or the amount of coal in the stockpile on site
20 at each plant, correct?

21 A. (Witness Hayet) Yes.

22 Q. And these inventory target ranges are
23 targets, not limits; right?

24 A. (Witness Hayet) That's correct.

25 Q. And the purpose of an inventory target is to

1 provide the company flexibility in how it manages
2 unexpected and temporary swings in inventory levels;
3 right?

4 A. (Witness Hayet) Yes. But as you notice on
5 page 7, the Commission had to approve a change. And at
6 one point it used to be 45 to 50. And it had been -- it
7 has -- had been widened in FCR-22 from -- between 40 and
8 50. So it is something that the Commission approves.

9 Q. Okay. You're anticipating where I'm going.
10 So at the time in FCR-22, when the range was widened, the
11 inventory target range was driven by the need to respond
12 to temporary delivery irregularities, whether
13 transportation or supplier related; correct?

14 A. (Witness Hayet) You're reading something. I
15 don't have that in front of me.

16 MS. PRYOR: Okay. May Mr. Hewitson approach?

17 CHAIRMAN SHAW: Yes.

18 Q. So I've handed you is a copy of the direct
19 testimony of Georgia Power witness Laura Patterson, on
20 behalf of Georgia Power in the FCR-22 case, Docket No.
21 33302. If you would turn to page 14 and 15, and I'm
22 referring to lines 17 through 19.

23 A. (Witness Newsome) On page 14?

24 Q. Yes.

25 So would you agree that this describes the

1 company's motivation for seeking a wider coal inventory
2 range from 45 to 50, to expand that to 40 to 50?

3 A. (Witness Hayet) Well, that's what it says.
4 I'm not -- I'm not -- I agree that's what it says.

5 Q. Okay. In the 15 years since FCR-22, would
6 you agree that there have been significant structural
7 changes, more specifically, declines in the coal supply
8 chain?

9 A. (Witness Hayet) Yes.

10 Q. Staff also reviewed the company's coal
11 purchases; is that correct?

12 A. (Witness Hayet) Yes.

13 Q. And in doing so, you undertook a detailed
14 review of the company's coal buy books; is that right?

15 A. (Witness Hayet) yeah.

16 Q. Okay. This includes review of the volume,
17 price, reason for procuring coal, bid solicitation, review
18 of the bids received, confirmations, analyses and purchase
19 orders; correct?

20 A. (Witness Hayet) Yeah. That's discussed on
21 page 28 of the testimony.

22 Q. And staff did not make a disallowance
23 recommendation related to any of the company's coal
24 purchases; correct?

25 A. (Witness Hayet) That's correct.

1 Q. And, Mr. Newsome, I think you mentioned in
2 response to Ms. Ariza's questions that in theory,
3 Commission staff does not disagree with the objective of
4 coal supply diversity; correct?

5 A. (Witness Newsome) Correct.

6 Q. And staff has not made a recommendation as to
7 the amount that it would be appropriate to pursue a
8 purchase for diversity purposes; is that right?

9 A. (Witness Hayet) That's correct. I mean, you
10 know, the company, it's a trade secret number, I believe,
11 as to how much of the company did. We have in our mind,
12 you know, what may be reasonable; however, we do think
13 that the company should develop a policy and include it in
14 their coal purchasing strategy documentation. That's
15 where we've gone with this sort of mini investigation that
16 we did as part of this proceeding.

17 Q. But you'd agree that the coal purchase in
18 question is a fraction of the company's overall portfolio;
19 correct?

20 A. (Witness Hayet) It's a -- it's an important
21 part of the company's portfolio. I would say that.

22 Q. But not high enough to make a disallowance or
23 recommendation that the coal purchase was imprudent;
24 correct?

25 A. (Witness Hayet) Well, first of all, this is

1 an issue that's a forward-looking issue for us. We
2 investigated the company's future purchasing plan of this
3 coal from this supplier. And so there is no disallowance
4 because we're not identifying costs that are higher in the
5 past that could be disallowed. We are suggesting that in
6 the future, we think it's important for the company to be
7 able to provide better justification, documentation of
8 policy and that sort of thing, you know, in case that the
9 issue comes up in the future. But we do think it's
10 important, and we are advising that we believe that the
11 company should address this as part of its coal purchasing
12 strategy documentation.

13 A. (Witness Newsome) And to follow up on that,
14 there's a percentage number, which are not getting into,
15 that's trade secret, but we'd like to see that -- you
16 know, right now, maybe we agree that percentage is okay.
17 And what happens if you come back and double it? You
18 know, there's kind of -- there's a lot of room there for
19 y'all to allow flexibility there.

20 And y'all may be able to justify having a
21 higher percentage, but that's kind of what we're concerned
22 about is that it's very loosey-goosey right now. And it
23 has to be because you have to make judgments. You've got
24 a lot of different things going on. You've got the coal
25 mines. You've got the transportation, what have you. But

1 it's real open-ended right now, so that's kind of our
2 concern.

3 A. (Witness Hayet) And another issue I'd like
4 to mention is that, just like in FCR-22, when the company
5 realized that it needed to widen the target inventory
6 level, if the company is, in fact, going to double, you
7 know, have inventory quite a bit higher than the target,
8 the company should consider whether or not that target is
9 appropriate, and reconsider that and consider whether or
10 not it wants to bring that to the Commission for
11 reconsideration, not just simply, you know, have a, you
12 know, major increase in the -- in the stockpile above the
13 inventory level.

14 Q. Thank you. Regarding staff's natural gas
15 hedging conclusions, this has been discussed several times
16 already. So I'll try to be brief about this, but it's
17 staff's conclusion that the current policy results in an
18 overall increase in fuel cost to customers; right?

19 A. (Witness Newsome) Yes. Yes.

20 Q. Okay. And you're aware, though, that the
21 purpose of the hedging program is to provide price
22 stability; right?

23 A. (Witness Newsome) Yes. But again, we're
24 more concerned about rate stability. And we get that by
25 the -- carrying a fuel balance and carrying costs as the

1 cost of that rate stability.

2 I'll make the point, I know you say it's good
3 for the ratepayer to have price stability on the natural
4 gas, but you may have a different attitude if you're
5 running these costs of your P&L. That's the problem. It
6 just keeps running through here.

7 And Commissioner Shaw made a good point.
8 Yeah, we like the insurance aspect of it. And you've
9 popped a few times where it's really been beneficial. In
10 fact, it happened this past February 2, too, you had a
11 nice gain. But then August, it all goes -- it gets
12 offset, and then it's even more offset. And so it goes
13 like 90 million a year for the last three years.

14 Q. So the net --

15 A. (Witness Newsome) I mean, I don't -- the
16 frustration, personally, for me, is this -- this money is
17 run through -- the customers taking all this, and y'all
18 just come back, hey, we're going to keep doing what we've
19 been doing. We haven't seen any effort on the company to
20 say, okay, how can we limit these losses?

21 In fact, he did a nice study, looked at your
22 different instruments, your swaps versus your collars.
23 One of them's a lot cheaper than the other. Well, maybe
24 you need to use them ones that are cheaper. I mean,
25 there's just no -- it's just more of the same. And that's

1 why we came -- we ended up at termination.

2 Q. The only disallowance this panel has
3 recommended is related to two fossil fuel outages; is that
4 correct?

5 A. (Witness Hayet) That's correct.

6 Q. And do you agree that the standard for
7 disallowance is whether the company's actions are illegal
8 or clearly imprudent?

9 A. (Witness Hayet) Are clearly imprudent?

10 Q. Illegal or clearly imprudent.

11 A. (Witness Hayet) That's right.

12 Q. Is this staff panel using the same clearly
13 imprudent standard as described by Witness Reynolds in his
14 testimony related to nuclear outages?

15 A. (Witness Hayet) I would say that we're
16 probably consistent, but I'm not going to sit here and say
17 that we're precise.

18 Q. You didn't separately identify a prudent
19 standard that you applied anything different than what he
20 did; is that correct?

21 A. (Witness Hayet) That's correct.

22 Q. And staff is not challenging the company's
23 replacement cost calculations or methodology; correct?

24 A. (Witness Hayet) We are not. We did point out
25 that there was an outage. It had to do with one of the

1 units. It's hard to describe it because it's trade
2 secret, but we identified one in the outages that could
3 have been in the same category as the two that we
4 addressed, and we did not take a disallowance on that
5 because the company didn't calculate a replacement cost on
6 that, and we found that somewhat curious, and we raised
7 that issue in our testimony.

8 Q. Okay. If I could get you to turn to page 36.
9 This is where you discuss the first outage. And if I
10 understand the reasoning staff provided, staff is
11 recommending a disallowance for this first outage because
12 it was caused by a human error and not an equipment
13 failure; is that correct?

14 A. (Witness Hayet) That's right.

15 Q. Is it staff's position that the outage is
16 clearly imprudent, if a human made a mistake?

17 A. (Witness Hayet) Yes. That's our...

18 Q. Okay. So are you recommending --

19 A. (Witness Newsome) They've got a
20 responsibility, the mechanic, whoever is working on it, to
21 check his work. And if he's not checking his work, his
22 foreman needs to check the work. There's procedures and
23 stuff. I mean, I worked in manufacturing facilities for
24 ten years as an engineer, not a mechanic.

25 But when you open the equipment up, there's

1 procedures, and that's your job to follow them. And
2 apparently that didn't happen here, or they didn't
3 understand what they're doing. Either way, we don't think
4 the ratepayers should be responsible for the cost of those
5 outages.

6 Q. But is it staff's opinion that a new standard
7 should be adopted that says human error by default is
8 imprudent?

9 A. No, but you missed something basic. We can't
10 go into details, but they were doing some -- replacing
11 some parts, and they put them in wrong.

12 Q. Okay.

13 A. I mean, your job is to check your work when
14 you're working in those kinds of environments, and the
15 mechanic can't do it. The foreman is responsible for it.

16 Q. But there was no --

17 A. (Witness Newsome) And it got missed. And so
18 the money, we don't feel like the ratepayers should absorb
19 it.

20 Q. But there was no finding that the company did
21 not have the proper processes in place; correct?

22 A. (Witness Hayet) No. There wasn't a finding
23 that the proper process was not in place.

24 Q. Okay. And there was no finding of improper
25 training, was there?

1 A. (Witness Newsome) They didn't put it in
2 correctly. I don't know what you did beforehand, but it
3 got put in wrong. That's the issue, and it shouldn't
4 been, should have been checked.

5 A. (Witness Hayet) I think that it was,
6 perhaps, in violation of the training. The training would
7 not have been to install it incorrectly.

8 Q. But there was no finding of failure to
9 oversee the employee, was there? Understanding that the
10 finding was that the position -- that the component was
11 installed incorrectly, there was no separate finding that
12 there was a failure to oversee the employee; correct?

13 A. (Witness Hayet) No, we don't have that in
14 the record, but there was no finding, but --

15 A. (Witness Newsome) I mean, there's nothing in
16 the record one way or the other on it.

17 Q. Was there any finding of a repeated mistake
18 or a failure of a corrected action program regarding this
19 outage?

20 A. (Witness Hayet) No.

21 Q. So this was just an isolated human error;
22 correct?

23 A. (Witness Newsome) Well, it cost us a bunch
24 of money.

25 Q. For the second outage, discussed on page 37,

1 I believe the logic -- or the outage was caused by a logic
2 error embedded in the software from the original equipment
3 manufacturer; is that correct?

4 A. (Witness Hayet) I think that's confidential,
5 but I think that's basically accurate.

6 Q. And does staff agree that the original
7 equipment manufacturer made the mistake at issue?

8 A. (Witness Newsome) That's true, but they're
9 working for you -- excuse me -- I'm sorry, working for
10 your client.

11 A. (Witness Hayet) Yeah. Yeah. I don't think
12 that we can sort of pass up on a situation because it was
13 somebody else's fault, if that's what you're getting at.

14 Q. But you would agree that all the appropriate
15 remediation actions that were taken were done on the part
16 of the original equipment manufacturer, not Georgia Power;
17 correct?

18 A. (Witness Hayet) What do you mean by
19 remediation actions?

20 Q. All of the process checks, retraining, all of
21 that happened with the equipment manufacturer; correct?

22 A. (Witness Newsome) After the fact? After the
23 incident? That was part -- that is possibly true, but
24 it's the ratepayers who are being responsible for the
25 additional fuel costs.

1 Q. And did you read Georgia Power's rebuttal
2 testimony on the second outage?

3 A. (Witness Hayet) Yeah. Yes.

4 Q. Okay. So you're aware, then, that that
5 original equipment manufacturer provided all the
6 replacement parts per -- and performed all necessary
7 repairs related to this incident free of charge to Georgia
8 Power?

9 A. (Witness Hayet) They didn't -- they didn't
10 provide replacement recovery for the customer who had to
11 pay the additional fuel costs for that period of time, and
12 it was a significant period of time. I mean, you know,
13 the amount is pretty -- it's a -- put it this way, I think
14 our -- as you mentioned, we have two adjustments, and the
15 total is \$10 million, and that was a significant portion
16 of the total.

17 Q. So it's staff's position that in both of
18 these outages, Georgia Power was clearly imprudent?

19 A. (Witness Newsome) Yeah. I mean, you
20 didn't -- people didn't do what they were supposed to do.

21 Q. If I could get you to turn to page 56,
22 Figure 8 purports to show commercial large load data
23 center load by month during the test period; is that
24 correct?

25 A. (Witness Wellborn) Yes. It's the forecasted

1 commercial large load projection.

2 Q. Okay. And you cite the company's response to
3 STF-JKA-127 as the source for that data; correct?

4 A. (Witness Wellborn) Yes.

5 Q. Do you have a copy of that data request with
6 you?

7 A. (Witness Wellborn) I don't think I do.

8 MS. PRYOR: Chair, may Mr. Hewitson approach?

9 CHAIRMAN SHAW: Yes.

10 BY MS. PRYOR:

11 Q. So, Panel, what I've handed you is a copy of
12 the company's response to STF-JKA-127, including the
13 attachment. I've included both the trade secret and
14 public disclosure version of that. Could you please read
15 the first sentence of the company's response?

16 A. (Witness Wellborn) The first sentence?

17 Q. Yes.

18 A. (Witness Wellborn) "Please see the
19 attachment for the class level annual calendar energy for
20 Southern Company and Georgia Power."

21 Q. And you agree that energy is quantified in
22 megawatt hours, rather than megawatts; correct?

23 A. (Witness Wellborn) That's true.

24 Q. And the referenced attachment in both
25 versions identifies that the data is in gigawatt hours in

1 the top left corner?

2 A. (Witness Wellborn) Yes.

3 Q. Okay. And turning back to Figure 8, this
4 data is shown in megawatts rather than megawatt hours?

5 A. (Witness Wellborn) Yes, but I believe we
6 also have a data response that was the hourly peak. That
7 reconciles with this energy. So I think they are tied.
8 Maybe the footnote is incorrectly placed, but I believe
9 that this is a monthly view of megawatts.

10 Q. But you'd agree that the data in the chart
11 didn't come from this response?

12 A. (Witness Wellborn) I would just need to
13 double-check. I believe they tied.

14 Q. Okay.

15 A. (Witness Wellborn) I think it was maybe 26
16 and 27 or sister DRs.

17 Q. Okay. Just a few final questions. You agree
18 that the company has not updated the RTP fuel credit
19 methodology in this case; correct?

20 A. (Witness Newsome) Correct.

21 Q. And this is -- the current methodology has
22 been in place for the last 16 years; do you agree?

23 A. (Witness Newsome) Correct.

24 Q. And the methodology was last approved by the
25 Commission in the 2010 rate case; right?

1 A. (Witness Newsome) Correct.

2 Q. And staff has recommended that in the future,
3 the company look at modifying the RTP credit methodology;
4 right?

5 A. (Witness Newsome) No. Our recommendation is
6 that we have an investigation to look at it, to figure out
7 what needs to be done. The methodology may be fine. It
8 may be your application in the methodology.

9 Q. Understood, but to be clear, you are not
10 recommending any changes as part of this proceeding;
11 right?

12 A. (Witness Newsome) No.

13 Q. Okay.

14 A. (Witness Newsome) Well, I've got the --
15 we've got the FT and the --

16 A. (Witness Wellborn) Yeah. I think we've
17 identified two issues that could be addressed in this
18 proceeding. But we also believe an investigation may be
19 an appropriate place to address comprehensively those two
20 issues and other issues. So we believe there's sufficient
21 evidence in this case that there is something related to
22 FT that needs to be addressed.

23 A. (Witness Newsome) Page 5, number 7, number
24 8.

25 Q. Yes. But your recommendation is to

1 investigate further, not to make any changes to the
2 methodology today as part of this proceeding?

3 A. (Witness Newsome) Well, we think these two
4 issues need to be dealt with, if y'all want to deal with
5 it. I mean, we think it should be dealt with. Now,
6 whether you're going to do it or not, is a different
7 story. But we -- it needs. And we filed an investigation
8 to figure out what else is going on. And we don't know
9 whether this is going to solve that delta force.

10 MS. PRYOR: No further questions at this
11 time. I'd like to mark Exhibits GPC 20, the
12 testimony of Laura Patterson, and GPC 21, the
13 company's response to JKA-127.

14 (The document referred to was marked for
15 identification as GPC Exhibit 20 and 21.)

16 COMMISSIONER HUBBARD: Can I ask a
17 question --

18 CHAIRMAN SHAW: Sure. Go ahead.

19 COMMISSIONER HUBBARD: -- as a follow-up, and
20 just to see how the opportunity as well. I just
21 want to follow up on something you said, Mr. Hayet.
22 You mentioned that it struck you that there's the
23 ability to include or exclude certain costs as fuel
24 costs. And you mentioned, I think, the
25 administration costs, renewable energy RFPs are

1 included, but the capacity RFP administration costs
2 or not.

3 So I'm just -- is it your opinion that
4 that -- and I also note on page 8 of your testimony
5 in the definition of fuel costs, number nine is
6 other costs or credits as determined by the
7 Commission for inclusion or reduction of
8 recoverable fuel costs.

9 So the idea that it's 100 percent fuel costs
10 pass through, we can -- the Commission can decide
11 to include or exclude certain things. And that is
12 one mechanism by which some costs that are fuel
13 costs can maybe not be passed through at
14 100 percent. Does that comport with what you were
15 saying is that we can include or exclude in your
16 definition of fuel costs, or what's in the actual
17 fuel costs definition, and the tariffs would
18 suggest that.

19 MR. HAYET: Yeah. Item number nine, I'll
20 just read it, just to make sure I'm -- "other costs
21 or credit as determined by the Commission for
22 inclusion in or reduction of" -- so I think it's --
23 it's up to the Commission to be able to decide if
24 additional costs, at the discretion of the
25 Commission, should be included in or removed from

1 the fuel recovery.

2 COMMISSIONER HUBBARD: And that power to
3 include or exclude costs in the fuel cost
4 definition is one way that we can amend fuel costs,
5 but also then disallowance. This is another way
6 that 100 percent of fuel costs might not be passed
7 through. Those seem to be two mechanisms by which
8 100 percent fuel costs might not be passed through.

9 MR. NEWSOME: Can you repeat the last part
10 real quick, that last part?

11 COMMISSIONER HUBBARD: So disallowances would
12 be one way that 100 percent fuel costs might not be
13 passed through.

14 MR. NEWSOME: Yes. But you have to have a
15 reason to do a disallowance --

16 COMMISSIONER HUBBARD: And not imprudent or
17 illegal.

18 MR. HAYET: And also I would say within the
19 law, I think you'd have to check the statute and
20 make sure that it's compatible with the -- with the
21 fuel cost recovery statute.

22 COMMISSIONER HUBBARD: But there are things
23 that could be included or excluded. I mean,
24 renewable energy credits are arguably not a fuel
25 cost, even if they're measured on a kilowatt-hour

1 basis.

2 MR. HAYET: Right.

3 COMMISSIONER HUBBARD: Like production tax
4 credits.

5 MR. HAYET: And there we were talking about
6 labor costs. That was the distinction. Labor --
7 or at least I was, talking about labor costs
8 related to renewables and why that should be
9 included in fuel cost recovery versus base rate
10 recovery relative to other RFPs that are run, and
11 labor costs associated with that and those going to
12 base rates. But I think -- I think you're right in
13 your thought process, though, and item number nine.
14 But, again, as long as it's within the law.

15 COMMISSIONER HUBBARD: Sure. Okay. Thank
16 you.

17 MS. PRYOR: May I ask one follow-up question?

18 RECROSS-EXAMINATION

19 BY MS. PRYOR:

20 Q. An example of a fuel cost that has gone
21 through the FCR rates, as part of that ninth definition of
22 what a fuel cost is in the tariff would be, for example,
23 the renewable RFP or renewable customer program costs that
24 the Commission has previously approved go through the FCR
25 in prior orders; correct?

1 A. (Witness Newsome) Yes. But it could also --

2 Q. Understood.

3 A. (Witness Hayet) And it could be amended.

4 Q. Sure. But it's just -- as an example of
5 something the Commission has previously permitted to go
6 through fuel through that portion of the definition.

7 A. (Witness Newsome) That's fair.

8 MS. PRYOR: Okay. Thank you.

9 CHAIRMAN SHAW: Redirect?

10 REDIRECT EXAMINATION

11 BY MR. COLLADO:

12 Q. Panel, the company asked a question about
13 whether under staff's recommendation, the recommended
14 changes to the IFR, whether the company would have to make
15 an adjustment, even if they oppose it. Do you remember
16 that question?

17 A. (Witness Newsome) Yes.

18 Q. Would you agree that ultimately an adjustment
19 would be a decision made by the PSC? And if the company
20 and staff and Commission all agreed not to change rates,
21 rates do not have to change; correct?

22 A. (Witness Newsome) Correct. I mean,
23 ultimately, it's a Commission decision. Our thinking on
24 that was to have a game plan rather than just keep kicking
25 down the road, propose a plan, bring the fuel balance

1 down, and then you put it before the Commission, they can
2 make a decision.

3 MR. COLLADO: Okay. I have no further
4 questions. I would just ask that -- Mr. Chairman,
5 if we could excuse the panel and have staff's
6 prefiled testimony and the exhibits be entered into
7 the record as STF-1.

8 CHAIRMAN SHAW: So marked.

9 Panel, you can be excused. Thank y'all for
10 your time.

11 If there are any specific requests, as far as
12 people's travel plans or anything that want to be
13 considered for any kind of change in the order,
14 we're certainly always willing to try to help folks
15 out and understand that.

16 But at the same time, I do think that
17 everybody realized they will not be finished today.
18 But if there are any special requests, I will take
19 those at this time.

20 All right. Noted.

21 Well, let's get things rolling. I will let
22 you, Chris, call up your next panelist and swear
23 him in and get started.

24 MR. COLLADO: All right. At this time I
25 would like to call Joseph Reynolds to the stand.

1 Mr. Reynolds, please stand up and raise your
2 right hand.

3 Thereupon,

4 JOSEPH R. REYNOLDS, P.E.,
5 having been duly sworn, testified as follows:

6 DIRECT EXAMINATION

7 BY MR. COLLADO:

8 Q You can take a seat.

9 So, Mr. Reynolds, on May 7th of this year,
10 did you prefile or cause to be prefiled 27 pages of
11 testimony in question-and-answer format, as well as
12 Exhibit STF-JRR-1?

13 A I did.

14 Q And on April 28th, did you file or cause to
15 be filed an errata to that testimony?

16 A Yes.

17 Q And if you were asked the same -- the same
18 questions today under oath, would your answers be the same
19 as those in your prefiled testimony and errata?

20 A Yes, they would be.

21 MR. COLLADO: Mr. Chairman, the court
22 reporter has been -- or will be given a copy of the
23 prefiled direct testimony with the exhibits and the
24 errata. I would ask that it be entered into the
25 record as if they were given here today.

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CHAIRMAN SHAW: So moved.

(Whereupon, the prefled direct testimony
and errata of Joseph Reynolds follows:)

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF: GEORGIA POWER
COMPANY'S FUEL COST RECOVERY
(FCR) APPLICATION (FCR-27)**

DOCKET NO. 56765

**DIRECT TESTIMONY
AND EXHIBITS
OF
Joseph R. Reynolds, PE**

**ON BEHALF OF THE
GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF**

PUBLIC DISCLOSURE

April 9, 2026

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Exhibits:

STF-JRR-1 Resume of Joseph R. Reynolds, PE.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Joseph R. Reynolds, PE. I am an executive and principal forensic electrical engineer with RTI Group, LLC (RTI). My business address is 401 Log Canoe Circle, Stevensville, Maryland, 21666.

Q. MR. REYNOLDS, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. My educational background includes postgraduate studies in engineering and mathematics following a B.E.S. degree in electrical engineering from the Johns Hopkins University. Prior academics include an A.A.S. degree in electrical technology from the Capitol Institute of Technology. More recent academic studies have included Fire and Explosion Dynamics at the University of Leeds and Basic British Law at the University of Liverpool in the UK. I am a member of the National Society of Professional Engineers and a licensed Professional Electrical Engineer.

With over 40 years of experience, I am internationally recognized as a senior forensic electrical engineer and an authority regarding the investigation and evaluation of power utility system incidents and equipment failures. This includes both nuclear and fossil plant accidents and outages along with transmission and distribution issues. My experience with nuclear plants includes consulting on both planned and unplanned outages for insurance companies, utilities, Original Equipment Manufacturers (OEM), as well as state and federal government commissions. Nuclear plant issues have involved reactor thermal shields, reactor fuel rods, steam generators, reactor cooling pumps, tubes, and valves. External to

1 the reactors, my experience at nuclear plants includes turbines, generators, the isophase bus
2 system, main Generator Step-up Unit (GSU) transformers and plant switch yard equipment.

3 I have had the pleasure of working with all those involved in nuclear systems, from the
4 suits downtown, to the plant manager and the hard hat workers on the plant floor.

5 My background in aviation accident investigation and safety has enabled me to draw on
6 the highly developed principles of root cause analysis and risk assessment techniques that
7 are applied to the nuclear industry. Thus, I have considerable experience in providing
8 recommendations for improved operations and equipment reliability and assessing
9 expected life and condition of aging equipment to prevent unplanned outages and
10 accidents.

11 This is my second Fuel Cost Recovery (FCR) Application consulting assignment from the
12 Georgia Public Service Commission (GPSC). I have testified on numerous occasions as an
13 expert witness in court on utility matters and in front of other public service commissions.

14 My resume is attached to this testimony as Exhibit STF-JRR-1.
15

16 **Q. WHAT IS THE NATURE OF YOUR BUSINESS?**

17 A. RTI Group, LLC was founded as FTI Consulting, Inc. (FTI) in 1982 and grew as a leading
18 provider of forensic engineering and scientific services worldwide. It was spun off in 2006
19 to allow FTI to pursue unrelated business opportunities. With over 350 engineering and
20 other specialists who represent RTI worldwide, our headquarters and research centre is
21 located in Stevensville, Maryland. In addition to this core engineering service, RTI
22 operates visual consulting services through its digital imaging and modelling studio. RTI
23 conducts bespoke testing services to study accidents and failures and now offers ISO/IEC

1 17025:2017 Accredited Independent Laboratory Testing Services in its materials and
2 electrical research laboratories. RTI is typically retained to investigate, determine root
3 causes, provide independent opinions effectively to help resolve legal matters, and solve
4 performance problems while representing its clients in regulatory hearings, press
5 conferences, and courts of law.

6
7 **Q. WHOM ARE YOU REPRESENTING IN THIS PROCEEDING?**

8 A. I am representing the Georgia Public Service Commission (“Commission”) Public Interest
9 Advocacy Staff (“Staff”) in this proceeding.

10
11 **Q. WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?**

12 A. I was asked to review forced outages with greater than 50,000 Megawatt-hour (“MWhs”)
13 production loss at Georgia Power Company’s (“Georgia Power” or “the Company”) Plants
14 Hatch and Vogtle during the period from May 2023 through September 2025. Following
15 my review, I was asked to provide an opinion on whether these outages were prudently
16 incurred or the result of imprudence. I was also asked to discuss the prudence standard and
17 to provide the Commission with some guidance, based upon my experience, in the
18 application of this standard in evaluating nuclear plant outages.

19
20 **Q. PLEASE DESCRIBE THE STEPS YOU TOOK TO CONDUCT YOUR REVIEW**
21 **OF THE OUTAGES AT PLANT HATCH AND PLANT VOGTLE.**

22 A. My first step was to review with Staff the tables of unplanned outages for the nuclear units
23 produced by the Company in their Fuel Cost Recovery Application filing in MFRH-4.1. I

1 then reviewed documents requested by Staff, including documents developed by Company
2 personnel to evaluate each outage, to identify causes of the outage, and to develop
3 corrective actions if necessary. Condition Reports, Event Investigation Reports, and Root
4 Cause Analysis Reports are examples of these documents. Finally, I interviewed Company
5 personnel to discuss outages of interest including the causes of the selected outages and the
6 corrective actions taken.

8 II. CONCLUSIONS AND RECOMMENDATIONS

9 **Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS**
10 **CONCERNING THE OUTAGES AT PLANTS HATCH AND VOGTLE THAT**
11 **YOU DISCUSS IN YOUR TESTIMONY?**

12 A. I conclude that four of the five outages described in detail below were avoidable and were
13 the result of clearly imprudent management, with the fifth outage being a manufacturer
14 defect. The Company had approximately [REDACTED] of lost generation due to
15 unplanned outages and derates at nuclear plants Hatch and Vogtle, excluding refueling
16 outages. The five imprudent outages resulted in approximately [REDACTED] of lost
17 nuclear generation. This demonstrates that Staff is not holding the Company to an
18 unreasonable standard or a standard of perfection. I recommend that incremental
19 replacement power costs to Georgia Power resulting from imprudently incurred outages in
20 the amount of \$[REDACTED] as discussed in my testimony, be disallowed.

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS WITH RESPECT TO DISALLOWANCES?

A. I recommend that the replacement power costs to Georgia Power, resulting from imprudently incurred outages in the amount shown below, be disallowed.

Unit	Event Number	Outage Start	Generation Loss (MWHs)	Incremental Replacement Cost
Hatch 2	26	09/13/2025		
Hatch 2	23	11/01/2023		
Vogtle 3	86	09/17/2024		
Vogtle 3	66	07/08/2024		
Vogtle 4	10	06/05/2024		
Total Due to Imprudence				

A detailed description of the outages at Plants Vogtle and Hatch that I reviewed is contained in my testimony.

III. PRUDENCE STANDARD

Q. PLEASE DESCRIBE THE STANDARD OF PRUDENCE THAT YOU APPLIED IN YOUR REVIEW OF THE PLANT HATCH AND PLANT VOGTLE OUTAGES.

A. I have applied the standard of prudence adopted by the Georgia Public Service Commission in Docket No. 6739-U, Review of Georgia Power Co.'s Rocky Mountain Pumped Storage Facility. The standard articulated by the Commission in the Rocky Mountain proceeding is as follows:

1 “A decision must not be judged as correct or incorrect in the light of perfect
2 hindsight. Rather, a decision must be judged as to whether it was reasonable
3 given the facts and circumstances which were known or which reasonably
4 should have been known at the time the decision was made. In applying
5 this standard, it must be recognized that in any decision-making process
6 there may exist a range of choices, any, or all of which could have been
7 adopted by reasonable management in good faith and under the same set of
8 circumstances. If the Company has made a decision which falls within that
9 “zone of reasonableness,” that decision must be found to have been prudent,
10 irrespective of whether others may have selected another alternative, and
11 irrespective of whether in hindsight another decision may now appear in
12 hindsight to have been a more correct decision.”

13
14 This standard is essentially a “reasonable man standard” in that the utility’s actions or
15 decisions are compared to the reasonable actions or decisions of a qualified and
16 experienced utility manager or operator given what was known, or reasonably should have
17 been known, at the time without benefit of hindsight. Thus, the actions and decisions of
18 Company personnel must be judged on what they knew, or reasonably should have known,
19 at the time the action was taken, or the decision was made without benefit of hindsight.
20 The “reasonable man standard” does not hold a Company responsible for actions or
21 decisions that may not have been appropriate had additional information been available at
22 the time certain actions or decisions were taken. I have applied this standard in my
23 evaluation of the Plant Hatch and Plant Vogtle outages discussed below.

1 **Q. PLEASE DESCRIBE IN MORE DETAIL THE APPLICATION OF THIS**
2 **STANDARD TO THE PRUDENT MAINTENANCE AND OPERATION OF**
3 **PLANT HATCH AND PLANT VOGTLE.**

4 A. Prudent maintenance and operation of Plants Hatch and Vogtle is the responsibility of
5 Company management. This requires that Company management establish the proper
6 environment and culture as well as provide effective programs and resources for plant
7 personnel. Management must establish high expectations for plant personnel and
8 equipment and is responsible for plant personnel and equipment performing at a high
9 standard. The appropriate environment and culture would include:

- 10 • Ensuring a safety-first priority;
- 11 • Providing adequate plant procedures;
- 12 • Maintaining a questioning attitude;
- 13 • Avoiding complacency;
- 14 • Identifying the risk associated with plant activities;
- 15 • Ensuring that plant equipment is maintained in good operating condition;
- 16 • Correcting known problems in a timely manner; and
- 17 • Requiring proper operating practices as described below.

18
19 In addition, management must ensure that the programs and procedures in use are effective.
20 An effective corrective action program is essential in safe and prudent plant operation.
21 This program defines the methods used in determining the cause of plant events and
22 ensuring that they are not repeated. The corrective action program must ensure that:

1 • Root cause analyses¹ are effective in determining the actual cause of the event
2 or problem.

3 • Root cause analyses are sufficiently broad to identify any generic implications
4 of the event.

5 • Corrective actions are effective in preventing a reoccurrence of the problem.

6 Plant personnel share the responsibility for operating the plant in a reasonable and prudent
7 manner in their decisions and actions. They must utilize the good operating practices and
8 techniques required by plant procedures and plant management. These practices include:

9 • Proper use of plant procedures;

10 • Adequate briefing of plant personnel;

11 • Proper communications techniques;

12 • Proper use of error detection practices such as self-verification, independent
13 verification, and peer checking.

14 • Safely stopping nuclear plant operation if anything unusual occurs.

15
16 **Q. WHAT GENERAL CRITERIA CAN BE USED TO IDENTIFY IMPRUDENT**
17 **OPERATION OF A NUCLEAR POWER PLANT?**

18 A. One must apply the definition of prudent operation, which compares operation of the plant
19 to operation by a reasonable and experienced plant management and staff given what was
20 known or should have been known at the time. Applying this definition requires

¹ A Root Cause Analysis is a detailed technical analysis of an event to determine why the event occurred and to identify corrective actions to preclude recurrence of the event.

1 specialized expertise and experience in nuclear plant operation. However, the response to
2 the questions below can be useful in making a prudence determination.

3
4 **Q. PLEASE DESCRIBE FACTORS YOU CONSIDER IN THE EVALUATION OF**
5 **PRUDENCE IN NUCLEAR PLANT OUTAGES.**

6 A. A nuclear plant forced outage is rarely the result of one simple mistake. There are often
7 precursor events and other opportunities for an outage to be avoided by prudent
8 management and plant operation. The following are factors that should be evaluated in
9 determining if an outage is prudently incurred or the result of clear imprudence:

- 10 • Have there been similar or related events in the past?
 - 11 ○ Were prior events entered into the corrective action program as required?
 - 12 ○ Are there indications of problems with the corrective action program or in
 - 13 problem identification and resolution?
 - 14 ○ Was the review of similar or related events broad enough to identify the
 - 15 potential for the event that caused the outage or was the review too narrowly
 - 16 focused?
 - 17 ○ Were the corrective actions by Company management and operators
 - 18 thorough and effective in preventing recurrence?
 - 19 ○ Was this a longstanding problem that had not been corrected?
 - 20 ○ Was the review of prior events by Company management of sufficient depth
 - 21 and rigor to identify and resolve the problem?

- 1 ○ Could the use of Operating Experience² have identified the problem and
- 2 avoided or mitigated the outage?
- 3 • If the event involves an operator error:
- 4 ○ Are there indications of human performance problems?
- 5 ○ Was the operator properly trained?
- 6 ○ Did the operator have the necessary education, experience, and training to
- 7 successfully perform the work?
- 8 ○ Were the procedures correct and adequate?
- 9 ○ Were the procedures followed?
- 10 ○ Would the procedures result in proper and prudent operation?
- 11 ○ Were operating techniques to minimize human performance errors
- 12 employed effectively?
- 13 ○ Were there other human factors involved that should have been identified?
- 14 • If the event involved equipment failure:
- 15 ○ Have there been similar equipment failures in the past?
- 16 ○ Were the corrective actions adequate and effective?
- 17 ○ Did management take steps to prevent or mitigate subsequent equipment
- 18 failures?
- 19 ○ Was prior maintenance performed in a timely manner?
- 20 ○ Was preventive maintenance adequate?

² Operating Experience includes experience gained at other nuclear plants with similar problems. Operating Experience is widely used in the nuclear industry to assist in resolution of common technical problems.

- 1 ○ Were there prior indications of equipment problems before the event?
- 2 ○ Was there Operating Experience available that should have alerted the
- 3 operator to the potential problem?
- 4 • If the event involved an engineering calculation or analysis:
- 5 ○ Have problems been identified with the adequacy or rigor of the engineering
- 6 calculations or analyses?
- 7 ○ Did the personnel performing the engineering analysis have the necessary
- 8 education, training, and experience to perform the analysis in a prudent
- 9 manner?
- 10 ○ Was the root cause determination appropriate?
- 11 ○ Was the engineering analysis given sufficient time for completion without
- 12 undue schedule pressure?
- 13 ○ Were proper engineering procedures followed?
- 14 ○ Was the engineering calculation or analysis adequately reviewed and
- 15 checked to confirm it was complete, correct, and accurate?
- 16 ○ Were there human performance issues?
- 17 ○ Was Operating Experience used effectively?
- 18

19 **Q. IN THE CASE OF FUEL RECOVERY COSTS, THE REQUIRED STANDARD IS**
20 **THAT THE OUTAGES MUST BE “CLEARLY IMPRUDENT” FOR THE**
21 **ADDITIONAL FUEL COSTS TO BE DISALLOWED. PLEASE DESCRIBE**
22 **YOUR UNDERSTANDING OF WHAT IS MEANT BY “CLEARLY**
23 **IMPRUDENT.”**

1 A. I have been advised by Staff counsel that any determination of whether conduct by the
2 Company was “clearly imprudent” is ultimately made by the Commission. A witness is
3 responsible for supporting his conclusion that conduct was imprudent. In my testimony, I
4 provide such support for my conclusion that certain conduct by the Company was
5 imprudent, applying the standard described above. After a witness testifies that certain
6 conduct was imprudent, it is up to the Commission to decide whether such imprudent
7 conduct was “clearly imprudent”, using whatever standard the Commission deems
8 appropriate. For example, the Commission could apply such commonly accepted standards
9 as “clear and convincing”, “preponderance of the evidence”, or “beyond a reasonable
10 doubt” in determining whether imprudent conduct was also clearly imprudent. While I
11 understand that the role of a witness is to support a conclusion that conduct was imprudent,
12 allowing the Commission to apply whatever standard it deems appropriate, the
13 Commission may desire that a witness recommend a standard to be applied by the
14 Commission when reviewing acts of imprudence. In my opinion, in determining whether
15 particular imprudent conduct is also clearly imprudent, the Commission should apply a
16 “clear and convincing evidence” level of scrutiny. The “clear and convincing evidence”
17 test is a medium level of scrutiny which is a more rigorous standard to meet than the
18 preponderance of the evidence standard, but a less rigorous standard to meet than proving
19 evidence beyond a reasonable doubt. In order to meet the standard and prove something by
20 clear and convincing evidence, a party must prove that it is substantially more likely than
21 not that it is true.

1 Applying this standard, it is my opinion that each of the outages described in this testimony
2 were the result of clear imprudence. That is, it is substantially more likely than not that the
3 outages described in this testimony were clearly imprudent.

4
5 **Q. PLEASE PROVIDE AN EXAMPLE OF HOW YOU WOULD APPLY THE**
6 **“CLEARLY IMPRUDENT” STANDARD.**

7 A. Assume an outage is caused by a plant operator placing a valve in the wrong position. As
8 discussed above, I examine the situation to include the following questions. Was the
9 operator properly trained to conduct this task? Was the operator following a procedure
10 properly? Was the procedure correct? Was the pre-job brief adequate? Was the operator
11 using error prevention techniques to prevent mistakes? Did the operator have a history of
12 mistakes? If the answers to these questions indicate that this was a one-time mistake by
13 the plant operator, I would likely conclude that the operator was imprudent in that he did
14 not take adequate care in conducting this activity. When I discover a pattern of similar
15 events, and actions to prevent this type of event were inadequate or not timely, I would
16 likely conclude this outage to be clearly imprudent. Similarly, if a plant has experienced
17 repeated failures of a plant component that led to an outage and has not identified and
18 implemented effective corrective actions to prevent recurrence of the failure in a timely
19 manner, I likely would conclude that this situation is clearly imprudent. Thus, a single,
20 one-time event may not be clearly imprudent depending on the circumstances, but an
21 outage that indicates a negative pattern or trend and a failure of corrective actions to prevent
22 recurrence of the event is clearly imprudent.

IV. REVIEW OF NUCLEAR PLANT OUTAGES

Q. PLEASE IDENTIFY THE OUTAGES AT PLANT HATCH AND PLANT VOGTLE THAT YOU REVIEWED.

A. Based on the criteria of resulting in greater than 50,000 megawatt-hours (MWHs) of lost generation, the following eight outages were selected for review:

- a. Hatch 1 Event 21 on 07/11/2025
- b. Hatch 2 Event 23 on 11/01/2023
- c. Hatch 2 Event 26 on 09/13/2025
- d. Vogtle 3 Event 66 on 07/08/2024
- e. Vogtle 3 Event 86 on 09/17/2024
- f. Vogtle 3 Event 92 on 11/17/2024
- g. Vogtle 4 Event 10 on 06/05/2024
- h. Vogtle 4 Event 42 on 03/23/2025

Q. PLEASE SUMMARIZE THE THREE OUTAGES THAT YOU FOUND NOT TO BE THE RESULT OF IMPRUDENCE AND PROVIDE THE GENERAL REASONS YOU DID NOT CONSIDER THESE OUTAGES TO BE THE RESULT OF IMPRUDENCE.

A. The identification of imprudence in nuclear power plant outages requires a detailed understanding of nuclear power plant operation to distinguish between prudent plant operation and imprudent operation. I applied the definition of imprudence and the general questions described above in my testimony to identify the outages for additional detailed review. Based on my experience, and using the criteria listed above, I determined that the three outages (Event numbers 21, 42, 92) were not clearly imprudent. Although we have not found these three outages to be clearly imprudent, there were some questionable issues³

³ Issues include unpreparedness leading to delays, vendor-related issues, and lack of information.

involved with each outage. Staff is not holding the Company to a standard of perfection and understands that mistakes will be made.

Q. WHILE YOU DID NOT FIND THESE THREE OUTAGES TO BE CLEARLY IMPRUDENT, THEY RESULTED IN ADDITIONAL COST TO RATEPAYERS. WHAT IS THE COST OF THE INCREMENTAL REPLACEMENT POWER FOR THESE THREE OUTAGES?

A. Ratepayers absorbed \$6.8 million Incremental Replacement Power costs due to these three outages.

Q. PLEASE SUMMARIZE STAFF'S POSITION ON THE FIVE OUTAGES WHICH STAFF IS RECOMMENDING A DISALLOWANCE.

A. Staff recommends a disallowance for the \$8.9 million incremental fuel replacement cost of these five outages given the criteria in the fuel cost recovery statute. However, it is Company management, rather than the ratepayers, that is responsible for their own imprudence and the performance of their Vendors. It would be fundamentally unfair for ratepayers to absorb this cost given the poor performance of Company management and their Vendors.

Q. DID YOU IDENTIFY A COMMON THREAD IN THE OUTAGES THAT YOU FOUND TO BE IMPRUDENT?

A. Yes, I did. The common thread in the two Plant Hatch 2 outages that I found to be imprudent is the Company's [REDACTED]

1 [REDACTED]
2 [REDACTED] These forced outages resulted in disciplinary actions
3 against a total of 5 Company employees, including one dismissal. The three Plant Vogtle
4 3 and 4 forced outages are directly related to [REDACTED], critical
5 single point failure design and inappropriate equipment installation. As noted above,
6 including these outages in this filing is fundamentally unfair and misguided. Relief should
7 be sought directly from the responsible Vendors, OEMs and construction contractors. In
8 fact, the Plant Vogtle 3, Event 66 occurred within the first year of operation and should
9 have been covered in the standard Vendor or OEM Warranties.
10

11 **Q. PLEASE DESCRIBE THE FIVE OUTAGES THAT YOU FOUND TO BE THE**
12 **RESULT OF IMPRUDENCE.**

13 A. First, I will describe the two Plant Hatch outages and then I will turn to the three Plant
14 Vogtle outages. The discussion will include a description of each outage, the Company's
15 findings, my analysis, and my conclusions.
16

17 **PLANT HATCH UNIT 2 EVENT 26 – 09/13/2025**

18 **Q. PLEASE BRIEFLY DESCRIBE THE HATCH UNIT 2 OUTAGE THAT BEGAN**
19 **ON 09/13/2025**

20 A. On September 13, 2025, at Hatch Unit 2, operators were performing a Turbine Control
21 Valve Fast Closure FT when both [REDACTED] unexpectedly tripped. Upon initial
22 investigation, human error was determined to be the cause where required control room

1 procedure steps had not been performed properly. This outage was avoidable and clearly
2 imprudent as described below.

3
4 **Q. PLEASE DESCRIBE THE HATCH UNIT 2 OUTAGE IN MORE DETAIL.**

5 A. On September 13, 2025, during a pre-shift meeting, supervisors set “hold points” in the
6 procedure where a supervisor is required to be present and approve certain critical steps
7 as they are completed. During this selection process, supervisors selected “hold points”
8 for observing some particular critical steps, but not all critical steps for this “High-Risk”
9 task. While performing a scheduled test of the [REDACTED]
10 [REDACTED], operators marked upcoming steps as “Not Applicable” (N/A) and then
11 continued to move forward with the procedure. When restarting the procedure, the
12 operators failed to go back to the correct page that required bypassing the [REDACTED].
13 This necessary bypass step was not performed, resulting in both recirculation pumps
14 tripping.

15
16 **Q. WHAT DID THE COMPANY FIND TO BE THE DIRECT CAUSE OF THIS**
17 **EVENT?**

18 A. The company conducted a Root Cause Analysis report and found that operators did not
19 perform place-keeping in a sequential manner as required per [REDACTED] for a
20 continuous use procedure. Contributing to this cause, operators did not identify the risk
21 associated with the [REDACTED] critical steps and therefore no hold point was created for the
22 supervisor to observe.

23
24 **Q. COULD THIS UNEXPECTED SHUTDOWN HAVE BEEN AVOIDED?**

A. Yes. If the proper steps and procedures were followed correctly, the operators would have known to bypass the [REDACTED] logic. In doing so, both recirculation pumps would not have tripped, and the unexpected shutdown would have not happened.

Q. WHAT DID THE COMPANY FIND TO BE THE ROOT AND CONTRIBUTING CAUSES TO THIS EVENT?

A. The Company found the following root and contributing causes of this event (Hatch CAR Number 893796):

ROOT CAUSE: Operators did not perform place-keeping in a sequential manner as required per [REDACTED] for a continuous use procedure.

CONTRIBUTING CAUSE(S): (from Company's Root Cause Analysis Report)
Operators did not identify the risk associated with the [REDACTED] critical steps and therefore no hold point was created for the supervisor to observe.
First Line Supervisor focused on completion of the tasks versus the application of Human Performance standards during the performance of a task in the entirety. Selective hold points for observing a selection of Critical Steps was utilized instead of all critical steps for the High-Risk task.

In summary, Company operators failed to identify the critical steps involved when performing the [REDACTED]. Unsupervised steps lead to the recirculation pumps tripping, causing the full reactor shutdown.

Q. WHERE THERE ANY DISCIPLINARY ACTIONS TAKEN AGAINST EMPLOYEES AS A RESULT OF THIS OUTAGE?

A. [REDACTED]

[REDACTED].

1
2 **Q. WHAT IS YOUR CONCLUSION REGARDING THE PRUDENCE OF THIS**
3 **OUTAGE?**

4 A. This outage was avoidable and the result of clearly imprudent management. Few forced
5 outages are as straightforward to review as this event that has been characterized by the
6 Company as [REDACTED] with [REDACTED]. Thus, my
7 conclusion is that the Company was imprudent to include the Plant Hatch Unit 2 Event 26
8 – 09/13/2025 in its Application for Incremental Replacement Cost of \$[REDACTED] and
9 should be disallowed.

10
11
12 **PLANT HATCH UNIT 2 EVENT 26 – 11/01/2023**
13

14 **Q. PLEASE DESCRIBE THE PLANT HATCH 2 OUTAGE THAT BEGAN ON**
15 **11/01/2023.**

16 A. On November 1, 2023, Hatch Unit 2, [REDACTED] was manually removed
17 from operation due to [REDACTED]. This led to the [REDACTED] tripping, which
18 resulted in a total loss of normal high pressure feedwater injection, ultimately causing a
19 manual shutdown of Unit 2.

20
21 **Q. PLEASE DESCRIBE THE HATCH UNIT 2 OUTAGE IN MORE DETAIL.**

22 A. The shearing of the [REDACTED] resulted in a leakage rate of 400 gallons per minute. Under
23 normal operating temperatures and pressure, the [REDACTED] are 325-degree Fahrenheit
24 and 325 PSIG. Due to the extreme temperature and pressure values, the water would flash
25 to steam upon exiting the pipe. This steam entered conduits and panel connections, in

1 particular, [REDACTED]. This panel contains [REDACTED], which is [REDACTED]
2 [REDACTED]. Water entered this [REDACTED], causing a short circuit which showed as a false low
3 suction indication for the [REDACTED]. The [REDACTED] received this signal, resulting in
4 an automatic trip of the [REDACTED]. The trip of the [REDACTED] caused a loss of feedwater flow
5 to the reactor. Operators then initiated a manual reactor SCRAM⁴ due to the loss of
6 feedwater.

7
8 **Q. WHAT DID THE COMPANY FIND TO BE THE CAUSE OF THIS OUTAGE?**

9 A. The company found that the cause of this was due to the [REDACTED] that was connected
10 to the [REDACTED] suction piping having sheared off from the half coupling due to
11 excessive stresses from low to high cycle fatigue. This resulted in a complete line break
12 creating a Feedwater System leak that required a shutdown to restore the system.

13
14 **Q. COULD THIS REACTOR MANUAL SCRAM HAVE BEEN AVOIDED?**

15 A. Yes. The Company was aware of the issue and did not fully analyze the situation. “An
16 improper mindset” contributed to the SCRAM as an ineffective U-Bolt was installed and
17 a pattern of vibration concerns were recorded but never studied, thus the reactor manual
18 SCRAM could have been avoided.

19
20 **Q. WHAT DID THE COMPANY FIND TO BE THE ROOT AND CONTRIBUTING**
21 **CAUSES TO THIS EVENT?**

22 A. The Company found the following root and contributing causes of this event (Local Root

⁴ Rapid emergency shutdown of a reactor by full insertion of control rods.

Cause Determination Report: NMP-GM-002_F09):

ROOT CAUSE: The failure of the [REDACTED] was caused by the installation of an unanalyzed pipe support in 2007. This resulted in support stanchion #1 being installed in the wrong location and in a configuration (U-Bolt) that restrained the axial motion of the pipe outside of industry best practices. This introduced stresses to the weld at the drain line branch connection causing the eventual failure due to low and high cycle fatigue (Flow and Thermal Cycling).

CONTRIBUTING CAUSE(S): Operations, Engineering, and Maintenance shift teams did not fully assess and validate their assumptions to understand ‘Why’ the support bracket repetitive failures were occurring due to a faulty mindset that the repeat failures were not system induced. This reduced the perceived risk by the shift resulting in the team not effectively engaging the larger organization to fully understand and resolve the issue.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PRUDENCE OF THIS OUTAGE?

A. The information provided by the Company for this outage show that for 16 years of operation, from 2007 to 2023, plant personnel failed to understand and resolve repeated failures of the defective drain line support system that led to the Manual SCRAM of Plant Hatch Unit 2 Event 26 – 11/01/2023. It is my conclusion that this forced outage was avoidable on numerous occasions and was due to imprudent management to address and prevent the [REDACTED] failure. Thus, it is my conclusion that the Company was imprudent to include the Plant Hatch Unit 2 Event 26 – 11/01/2023 outage in its Application for Incremental Replacement Cost of \$ [REDACTED] and should be disallowed.

PLANT VOGTLE UNIT 3 EVENT 86 – 09/17/2024

Q. PLEASE DESCRIBE THE PLANT VOGTLE UNIT 1 OUTAGE THAT BEGAN ON 09/17/2024.

A. On September 17, 2024, Vogtle Unit 3 experienced a failure at the [REDACTED], which was expected to be in the closed position but was rather fully in the open position. This resulted in an automatic trip of Vogtle Unit 3.

Q. WHAT DID THE COMPANY FIND TO BE THE CAUSE OF THIS EQUIPMENT FAILURE?

A. The company found that the cause of the failure was due to a premature [REDACTED]. The result of the failing [REDACTED] was the [REDACTED] losing air supply and actuating to the fail state open position.

Q. COULD THIS OUTAGE HAVE BEEN AVOIDED?

A. The outage was caused by a single point failure in response to the programmed reactor trip logic which was triggered by a single [REDACTED] fuse that may have been defective. For these reasons, the Company could not have avoided this forced outage.

Q. WHAT DID THE COMPANY DETERMINE TO BE A CONTRIBUTING CAUSE OF THE FAILURE?

A. Inadequate risk management is a contributing factor in the cause of this failure. [REDACTED] were incorrectly classified as a Run-to-Maintenance Component but rather should be classified

as a Critical Component. Single point failure components should always be classified as a Critical Component with regular inspections.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PRUDENCE OF THIS OUTAGE?

A. The subject Outage occurred about 14 months after Plant Vogtle 3 was placed in service on July 31, 2023. The Company determined the cause to be due to the premature failure of a [REDACTED] on [REDACTED] from its expected closed position to 100% open. It is my opinion this resulted in an automatic trip of Unit 3 due to a faulty trip circuit logic interlock. Although the analysis of the [REDACTED] failure was extensive, the most critical issue was the exposure of a single point failure designed into the Unit 3 trip circuit logic. A correction to the trip circuit software is currently being redesigned by the OEM. It is my conclusion that the OEM protection system design on the [REDACTED] [REDACTED] was imprudent by not classifying the [REDACTED] as a “Critical Component”. Therefore, ratepayers should not be responsible for this unnecessary replacement fuel cost that is associated with the plant shutdown caused by a defective design.

PLANT VOGTLE UNIT 3 EVENT 66 – 07/08/2024

Q. PLEASE DESCRIBE THE PLANT VOGTLE UNIT 3 OUTAGE THAT BEGAN ON 07/08/2024.

A. On July 8, 2024, Vogtle 3 experienced a failure when its [REDACTED] [REDACTED] unexpectedly moved from its closed position to a fully open

1 position. This resulted in a loss of forward flow, causing water levels in the Steam
2 Generators to drop. Steam Generator Narrow Ranger water levels reached 26%, at which
3 point operators initiated a manual reactor trip.

4
5 **Q. WHAT DID THE COMPANY FIND TO BE THE CAUSE OF THIS EQUIPMENT**
6 **FAILURE?**

7 A. The company found [REDACTED] inside of the positioner internal pressure regulator.
8 The Company determined from its records that the [REDACTED] must have been
9 introduced during its assembly by the manufacturer.

10
11 **Q. WHAT DID THE COMPANY DETERMINE TO BE A CONTRIBUTING CAUSES**
12 **OF THE FAILURE?**

13 A. When readings dropped momentarily on [REDACTED]
14 [REDACTED]
15 [REDACTED], this triggered actuation on the [REDACTED]. This
16 momentary drop in reading was sufficient to satisfy 2 out of 4 channels and 1 out of 2
17 Steam Generator Logic, resulting in the [REDACTED]. This [REDACTED] was
18 unnecessary during a momentary drop in SGWR signals. The Company states there will
19 be a PMS setpoint or software update that will be developed to prevent this unnecessary
20 [REDACTED].

21
22 **Q. COULD THIS OUTAGE HAVE BEEN AVOIDED?**

1 A. Yes, if the manufacturer did not introduce the [REDACTED] into the valve, the outage
2 would have been avoided.

3
4 **Q. WHAT IS YOUR CONCLUSION REGARDING THE PRUDENCE OF THIS**
5 **OUTAGE?**

6 A. Based on the investigation conducted by the Company it is my conclusion that the subject
7 [REDACTED] was defective when installed. Its failure occurred within the first year of
8 Plant Vogtle 3 operation. Therefore, it is my conclusion that it was imprudent on the
9 manufacturer of the [REDACTED] to introduce the [REDACTED] that caused the
10 malfunction.

11
12 **PLANT VOGTLE UNIT 4 EVENT 10 – 06/05/2024**

13
14 **Q. PLEASE DESCRIBE THE PLANT VOGTLE UNIT 4 OUTAGE THAT BEGAN ON**
15 **06/05/2024.**

16 A. On June 6, 2024, Vogtle Unit 4 [REDACTED] tripped on a spurious high signal
17 of the [REDACTED]. A Turbine runback and [REDACTED]
18 [REDACTED] occurred resulting from the [REDACTED] trip. Ultimately, temperature deviation rose to
19 +10 degrees Fahrenheit, leading the operators to perform a manual trip of the reactor.

20
21 **Q. WHAT DID THE COMPANY FIND TO BE THE CAUSE OF THIS EQUIPMENT**
22 **FAILURE?**

1 A. The [REDACTED] high signal was caused by a [REDACTED] in the
2 termination block within the MFW Pump C Motor Accessory Terminal Box, causing MFW
3 Pump C Package to trip, followed by a turbine runback.

4
5 **Q. WHAT DID THE COMPANY DETERMINE TO BE A CONTRIBUTING CAUSES**
6 **OF THE FAILURE?**

7 A. The terminal block was damaged at the termination point, resulting in the [REDACTED] being unable
8 to lock into place.

9
10 **Q. COULD THIS OUTAGE HAVE BEEN AVOIDED?**

11 A. Yes, work practice during construction was less than adequate. If there was proper
12 installation of terminal block and wiring, this outage would have been avoided.

13
14 **Q. WHAT IS YOUR CONCLUSION REGARDING THE PRUDENCE OF THIS**
15 **OUTAGE?**

16 A. This outage occurred within 36 days following the in-service date for Plant Vogtle 4 on
17 April 29, 2024. Company documents indicate in the Equipment Failure Summary that
18 [REDACTED] and [REDACTED]
19 [REDACTED]. These comments were related to the root cause of the outage described as [REDACTED]
20 [REDACTED]. It is my conclusion that the installation vendors were
21 imprudent in the selection of the [REDACTED] and installation of its wiring, and that
22 this outage is clearly a warranty item. Therefore, ratepayers should not be held responsible
23 for paying the replacement fuel cost of this outage.

1 **Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

2 A. Yes, it does.

EXHIBIT STF-JRR-1
Resume Of
JOSEPH R. REYNOLDS, PE

Joseph R. Reynolds, PE.
Principal Forensic Engineer

Summary

Joseph R. Reynolds, PE. is internationally recognized as a forensic engineer and an authority regarding the investigation and evaluation of utility system incidents, including power generation and distribution equipment failures as well as electrical contact accidents, fires and explosions. He has served as the team leader and technical director, as well as principal testifier, in large complex investigations and research. Services to the industry have included: conducting forensic root cause analyses of major power generation, transmission, distribution, telecommunications, system failures, accidents, fires, and equipment condition and performance audit issues; providing recommendations for improved equipment reliability; assessing the expected life and condition of aging equipment for repair/replace options; and addressing prudence issues related to rate base and regulatory hearings.

Mr. Reynolds is the founder and president of RTI Group, LLC based in the US, as well as the founder and chairman of the London based UK firm Reynolds Technological Inquiries Limited. The RTI companies are an international consultancy of experienced expert witnesses supported by a accredited and certified ISO/IEC 17025:2017 independent testing laboratory located in its Maryland Research Centre to determine the cause of electrical, material, and mechanical failures. An advance multimedia studio provides the visuals to effectively present key expert findings. A highly diversified firm, RTI specializes in accident and failure analysis of various size matters involving aviation, marine, rail, telecommunications, power utilities, and high risk industries.

RTI also provides proactive consulting services from Safety Management Systems (SMS) to Security Risk Assessments.

Mr. Reynolds has represented public and government utilities, state regulatory commissions, and OEM insurers in numerous electric power matters, including the following examples:

- Appointed by a utility regulator to serve as lead investigator and team manager for the state's official investigation and analysis of a high-profile utility service outage resulting in recommendations to improve system reliability, which were adopted through the legislative rule-making process.
- Investigated regional blackouts as well as numerous power plant issues.
- Provided testimony at rate base hearings before state public service commissions involving the utility's handling of unplanned plant outages, and evaluation of the resulting repair costs.

- Authored several publications on behalf of the Electric Power Research Institute, EPRI, including a guideline to assist utilities in improving the reliability of power plant electrical equipment as an alternative to the cost of constructing new plants.
- Author of EPRI guide to the Forensic Investigation of Distribution Systems Accidents. Provided member utilities training over 2 years based on this report.
- Evaluated the options to restore the performance of a damaged hydroelectric generator station when compared with the availability of replacement power.

Mr. Reynolds has given expert testimony in arbitration hearings and courts of law, and has appeared before state and federal boards, commissions, counsels, press conferences, and international professional forums.

Academic Background

- Postgraduate Studies, Engineering and Mathematics, The Johns Hopkins University, Baltimore, Maryland.
- B.E.S., Electrical Engineering, The Johns Hopkins University, Baltimore, Maryland.
- A.A.S., Electrical Technology, The Capitol Institute of Technology, Washington, D.C.
- University of Leeds, Fire/Explosion Dynamics, United Kingdom.
- University of Liverpool, Basic British Law, United Kingdom.
- The Royal Society of Medicine, British Court Procedures, United Kingdom.

Registration

- Registered Professional Engineer, Electrical: Maryland

Professional Experience

- Founder and President of RTI Group, LLC (RTI), Annapolis, MD, February 2006 to present.
- Founder and CEO of Reynolds Technological Inquiries Limited, RTI Ltd (RTI), London, UK, July 2005 to 2020.
- Founder and President of Reynolds Technologies International, LLC (RTI), wholly owned subsidiary of FTI Consulting, Inc., Annapolis, MD, 2003 – 2004.
- CEO and Executive Director, Anamet, Inc., Hayward, California, 2003 – 2016. Re-established materials engineering and testing laboratory originally founded in 1958.
- Co-founder, FTI Consulting, Inc., Annapolis, Maryland, 1982 - 2003. Served as Senior Vice President, Chief Scientist, President, Vice Chairman and Chairman. Team leader and principal investigator on numerous major loss investigations, product and systems reliability research and safety analysis reviews, while serving as the head of all Engineering and Scientific Services that became the Applied Sciences Consulting Division.

- Director, Forensic Engineering Directorate, ManTech International Corporation, CADCOM Division, 1975-1982. Established and developed forensic engineering analysis services while directing and conducting investigations and research involving aging power generation equipment, electrical accidents and equipment failures.
- Director and Principal Research Engineer, Trident Engineering, Annapolis, Maryland, 1969-1975. Managed environmental and life sciences instrumentation products research and beta testing. Participated in writing System Safety Manuals for NASA flight systems. Established Safety Engineering Department; directed and conducted root cause failure investigations primarily in the areas of aircraft accidents, fires, explosions, and electric utility generation, transmission and distribution equipment failures and repair/replacement options.
- Research Assistant, The Johns Hopkins University, Baltimore, Maryland, 1965-1969. Assigned to the Mossbauer Effects Studies Group utilizing a 50 Mev Van de Graaff generator laboratory. Responsibilities included designing electronic instrumentation systems for use in this sub-atomic particle research under the direction of the Physics Department. Assigned to the Carlyle Barton Laboratory where research involved aircraft electronics and radar systems. Additional experience with military aircraft strategic systems applications and research.

Professional Associations and Activities

- Academy of Experts of London, Vetted Member
- Advisory Committee, G.W.C. WSE, JHU
- American Society of Safety Engineers, Professional Member
- Avionics and Aircraft Electrical Systems Failure Analysis
- Cockpit Accident Sequence Reconstruction
- Expert Witness Institute of London, Full Member
- Institute of Civil Protection and Emergency Management, Fellow Member
- Institute of Electrical and Electronics Engineers, Life Senior Member: Aerospace and Electronic Systems Society - Dielectrics and Electrical Insulation Society - Power Engineering Society
- International Association of Arson Investigators, Member
- International Society of Air Safety Investigators, Member No. MO3982
- The Johns Hopkins University Board of Trustees
- The Johns Hopkins University, Whiting School of Engineering, National Advisory Council
- National Fire Protection Association, Life Member
- National Society of Professional Engineers, Member
- Nautical Institute, Member
- Tau Beta Pi, National Engineering Honorary Society

Research Activities

- Electric Generator Core Iron Condition Evaluation
- Electric Power Generation Plant Life Extension versus Replacement Assessment Strategies
- Steam turbine blade failures and nuclear steam generator issues
- Electric Power and Telecommunications Systems Fault Analysis
- Electrical Fire Ignition Research
- Electrical Insulation Failure Analyses
- Flight Path Reconstruction and Visualization
- Forensic Investigation of Electrical Distribution Systems
- Computer Modelling and Animation Applications
- High-Energy Particle Physics Research
- Reconstructive Fire Science and Full-Scale Burn Testing
- Lithium Battery Safety
- Partial Discharge in Cable Terminations
- Electrical Safety and Standards
- Electrical Shock and Contact Hazards
- LED Technology
- AI

Lectures and Presentations

Frequent speaker and seminar presenter and guest lecturer for a variety of groups and organizations including:

- The Federal Judicial Centre Research Division
- Natural Gas Claims and Litigation Association
- National Fire Protection Association (NFPA)
- William and Mary School of Law, Courtroom 21 Project
- Institute of Electrical and Electronics Engineers (IEEE)
- American Society of Safety Engineers (ASSE)
- International Association of Arson Investigators (IAAI)
- Insurance Risk Management Organizations
- The Telecommunications Industry
- The Johns Hopkins University Whiting School of Engineering
- University of Maryland, School of Engineering
- Morgan State University School of Engineering
- National Institute of Standards and Technology, Centre for Fire Research
- Society of Fire Protection Engineers (SFPE)
- International Society of Air Safety Investigators (ISASI)
- Georgetown University Law School, Aviation Law Lecturer
- Baltimore City Fire Department (Advanced Arson Investigation Training Seminar)
- Inns of Court School of Law, Lloyds
- American Bar Association (ABA)
- Consumer Product Safety Commission Training Seminar

- Electric Power Research Institute (EPRI), Inc.
- Expert Witness Institute
- AON Limited
- AViCON
- Lawline

Selected Publications and Presentations

- Reynolds, J.R., PE, MEWI, MAE, Hull, S., I Eng FRAeS, “Present and Future Challenges in Aviation Claims Resolution,” AViCON 2015, Technical Programme, Stevensville, Maryland, September 2015.
- Reynolds, J.R., PE, MEWI, MAE, Alimonti, F., Alexander, B., Amster, D. Latta, D., “Aviation Litigation: The View From 30,000 feet,” Live Cable Broadcast, Lawline, Division of Further Ed, New York, NY, 19 May 2015.
- Reynolds, J.R., PE, MEWI, MAE, Hull, S., I Eng FRAeS, “Investigating the Causes, Resolving the Claims,” AViCON 2012, Technical Programme, New York, NY, 25 April 2012.
- Reynolds, J.R., PE, MEWI, MAE, Mitchell, S., PhD, “Disaster in the Islands,” AViCON 2010, Technical Programme, London, UK, November 2010.
- Reynolds, J.R., PE, MEWI, MAE, Mitchell, S., PhD, “Disaster in the Islands,” AViCON 2010, Technical Programme, London, UK, November 2010.
- Reynolds, J.R., AASc CEEng BEng PE MISASI MEWI MAE, “A Baltic Accident – Casualty Investigation,” Marine Investigation & Mediation Conference, Athen, Greece, October 2009.
- Reynolds, J.R., PE, MEWI, Mitchell, S., PhD, “Forensic Services Presentation,” AViCON 2009 Technical Programme, New York City, NY, May 2009.
- Reynolds, J.R., PE, MEWI, Braithwaite, G., PhD, “Investigating the Disaster,” AViCON 2008, Technical Programme, London, UK, October 2008.
- Reynolds, J.R., PE, MEWI, “Reconstructing Property and Casualty Events Using Digital Evidence: The Role of the Forensic Expert Investigator,” Subrogation and Recovery in the Property and Casualty Insurance Markets, London Underwriting Centre, March 2007.
- Reynolds, J.R., Crowch, T., West, K., “Investigation Strategies in Complex Claims Handling,” 2006.

- Reynolds, J.R., PE, MEWI, Reynolds Technological Inquiries Limited, “Reconstructing Property and Casualty Events Using Digital Evidence: The Role of a Forensic Expert Investigator,” 2007.
- Reynolds, J.R., PE, MEWI, “FTI Consulting, Inc.: Case Study,” The Johns Hopkins University Invitation to Entrepreneurship, 2005.
- Reynolds, J.R., AASc CEEng BEng PE MISASI MEWI, “The Expert Witness in North America,” 2004.
- Reynolds, J.R., AASc CEEng BEng PE MISASI MEWI, “Expert Evidence at Home and Abroad,” Royal College of Physicians – Regents Park, London, January 2004.
- Reynolds, J.R., Manger, H.C., “Root Cause Analysis Following Failures: A Review of EPRI Technical Report 1001890,” 2004 International Conference of Doble Clients, Boston, MA, March 2004.
- Reynolds, J.R., Manger, H.C., “Transformers, We’ve Come A Long Way,” Doble – The Life of a Transformer Seminar, February 2004.
- Reynolds, J.R., Manger, H.C. “The ABC’s of Conducting a Transformer Failure Investigation,” 2004 Large Power Transformer Seminar, Doble, Clearwater, Florida, February 2004.
- Reynolds, J.R., Manger, H.C. “From Transformer Incident ... To Court,” Weidmann-ACTI, Inc. Second Annual Conference Miami Beach, FL, November 2003.
- Reynolds, J.R., Manger, H.C. “The Engineer in Court,” International Conference of Doble Clients, Boston, MA, April 2003.
- Reynolds, J. R.; Manger, H.C.; Samm, R., The Fundamentals of Forensic Investigation Procedures Guidebook, EPRI Technical Report 1001890, March 2003.
- Reynolds, J. R.; Manager, H.C., “The Engineer in Court,” 2003 International Conference of Doble Clients, Boston, Massachusetts, April 6 – 11, 2003.
- Reynolds, J. R., “The Role of the Forensic Expert Investigator, Reconstructing the Casualty Using Digital Evidence.” Subrogation and Recovery in the Property and Casualty Insurance Markets Conference, Lloyds of London, 5 February 2002.
- Reynolds, J. R., Manger, H.C., “Journal of an Expert Witness, Part 2 – The Trial.” TJH2b TechCon 2002, Tampa Bay, Florida, January 23-25, 2002.

- Reynolds, J. R., Butler, T.W., “A Comparative Analysis of Three Generator Core Failures.” EPRI Conference, The International Workshop on Maintaining the Integrity of Generator Cores, San Antonio, Texas, November 28-30, 2001.
- Reynolds, J. R., “Reconstructing the Casualty: Digital Evidence,” Eagle International Associates, International Claims Handling Conference, Lloyd’s of London, 8 October 2001.
- Reynolds, J. R., “The Expert Witness in the U.S.A.” The Annual EWI Conference 2002
- Royal College of Physicians, Regents Park, London, 26 September 2001.
- Reynolds, J. R., Manger, H. C., “You have been Summoned to be Deposed – Now What?” 2001 International Conference of Doble Clients, Boston, Massachusetts, April 1-6, 2001.
- Reynolds, J. R., Manger, H. C., “Electrical Maintenance Professionals in Litigation – as Deposition Witnesses.” NETA Annual Conference, Kansas City, Missouri, March 2001.
- Reynolds, J. R., H. Carl Manger, “Journal of an Expert Witness, Part 1 – The Deposition.” TechCon 2001 Conference, Mesa, Arizona, February 2001.
- Reynolds, J. R., Bayan, F.P., “Achieving the Virtual Cockpit,” ISASI Forum, October-December 1999.
- Reynolds, J. R., “Forensic Animation of a Fire Analysis (the Dupont Plaza Hotel Fire Computer Modeling Analysis).” Forensic Techniques for the 21st Century, Lloyd’s of London October 16-17, 2000.
- Reynolds, J. R., “The Forensic Engineering Investigation of Power Distribution Equipment Failures.” EPRI Conference, Phoenix, Arizona, October, 5, 1999.
- Reynolds, J. R. “Scientific and Engineering Animations Advance.” *New York Law Journal*, August 1999.
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- Reynolds, J. R. “Generic Guidelines for the Life Extension of Plant Electrical Equipment.” Electric Power Research Institute. July 1988.
- Reynolds, J. R. “Least Cost Gauge Buoy for Measurement and Analysis of Ocean Waves.” *International Symposium on Ocean Wave Measurement and Analysis* Vol. 1. A.S.C.E. (September 1974): 639.

Matter:	FCR-27	Original File:	J. Reynolds Testimony FCR-27-TS-FINAL
Docket No.	56765	Original File Dated:	8-Apr-26
Testimony of:	Joseph Reynolds	Date Filed:	9-Apr-26
Page	Line	Correction	Reason
15	16	It would be fundamentally unfair for ratepayers to absorb this cost given the poor performance of Company management and their Vendors.	"Venders" was capatilized in new version
19	17	Footnote 4, "Full shear of the suction line occurs when the small drain line breaks completely away from the larger feedwater supply line. See Figure 2 – Location of failure in 1” pipe stub between socket welded connections -Pg 6 of 134 NMP-GM-002-F09"	
22	14	Loss of this fuse then caused an automatic reactor trip due to excessive cooldown and rapid power reduction from a steady state of 100% power.	This sentence was added to the answer of the question.
23	15	Therefore, ratepayers should not be responsible for this unnecessary replacement fuel cost that is associated with the plant shutdown caused by a Vendor defective design.	Grammar and Punctuation
24	7	The company found foreign material inside of the positioner internal pressure regulator of the main feedwater control valve.	Further explanation
24	9	The Company determined from its records that the foreign material must have been introduced during its assembly by the manufacturer.	Changed the word "the" to "it's".

25	8	Therefore, it is my conclusion that it was imprudent for the Vendor manufacturer of the Feedwater Valve to allow foreign material to be contaminating the valve that caused its malfunction.	
25	18	Ultimately, temperature deviation rose to +10 degrees Fahrenheit, leading the operators to perform a manual trip of the reactor.	Grammar and Punctuation
26	11	"Yes, work practice during construction was less than adequate." Footnote 6 - "See Photograph of subject terminal block installation. Pg. 3 of 16, NMP-GM-002-F22"	Footnote 6 was added.
26	20	It is my conclusion that the installation Vendors were imprudent in the selection of the terminal component and installation of it's wiring, and that this outage is clearly a warranty item. Therefore, ratepayers should not be held responsible for paying the replacement fuel cost of this outage caused by Venders.	Grammar and Punctuation
28	-	Provided testimony at rate base hearings before state public service commissions involving the utility's handling of unplanned plant outages, and evaluation of the resulting repair costs.	Grammar and Punctuation - made "hearing" plural

1 MR. COLLADO: With your permission, may
2 Mr. Reynolds give a summary of his testimony?

3 CHAIRMAN SHAW: Yes, sir. Go ahead.

4 MR. REYNOLDS: My testimony, and I am
5 reviewing materials attained from Georgia Power
6 regarding outages that occurred during the period
7 2023 to 2025 in excess of 50,000 megawatt-hours.
8 These outages were unplanned -- unplanned and
9 were --

10 CHAIRMAN SHAW: Mr. Reynolds, if you don't
11 mind, slide that microphone a little bit. Thank
12 you, sir.

13 MR. REYNOLDS: I am glad to do that. Thank
14 you. I'm having a hard time hearing. I guess,
15 there's a fan behind me.

16 So, anyway, we had a chance to review the
17 list of outages occurring over that time period of
18 2023 to 2025 that exceeded 50,000-megawatt hours
19 and were total shutdowns. Unexpected, unplanned
20 and were expensive, in terms of producing power.

21 My particular responsibility was to find out
22 why they occurred, to find out if the cause of
23 those outages were prudent or imprudent, as far as
24 the actions of Georgia Power personnel were
25 concerned.

1 In reviewing those, there were approximately
2 10 or 12 that were on the list of suspect to look
3 at and to review. Of those ten, we ended up
4 selecting five, five particular outages that we
5 felt required scrutiny as far as the prudence of
6 actions of personnel at the time of the incident.

7 The one thing we were using was the
8 definition of prudence, which was developed during
9 the Rocky Mountain outage, a pump storage facility
10 issue some years ago, which basically said we can't
11 use hindsight as a reason. We can't look at it
12 from the standpoint of we should have known from
13 the past. But it's based upon what was known at
14 the time of the incident.

15 What were the conditions? What were the
16 operations being handled? What were the activities
17 of people? And more importantly -- it turned out,
18 more importantly, what was the condition of
19 equipment that was at play and was the cause of the
20 incidents?

21 So in doing those particular reviews, we
22 utilized all materials provided by Georgia Power.
23 They provided reports and materials related to the
24 outages, their summaries of their responses, their
25 recommendations, their findings in written format.

1 We also had a chance to interview and discuss these
2 matters with Georgia Power engineering and
3 personnel.

4 Besides that, we were looking into the
5 activities that took place from a time standpoint.
6 What we like to do is put things in perspective as
7 to the time, time scale, or we call it the timeline
8 of events. What was the first event to occur?
9 What was the second? What was the sequence?

10 Those sequences often reveal a series of
11 things that go wrong. It's very seldom there's
12 just one issue that causes a shutdown. It's a
13 series of events which lead up to it.

14 And in doing so, we found that of those five
15 that we looked at very carefully, you did find that
16 they were actually falling in the category of
17 imprudent actions and imprudent issues. Three of
18 those particular failures, we think, were related
19 primarily to equipment or design inadequacies by
20 the OEM, or vendors supplying materials to the
21 plants.

22 Two were related to human error, or I would
23 call it mistakes that were not really excusable.
24 In fact, the two we referred to in those cases at
25 Hatch resulted in the dismissal of personnel and

1 also the demotion of personnel, which emphasized
2 the fact that internally there was a concern for
3 the activities of these particular personnel.

4 But that made it clear that not only we felt
5 it was improper or imprudent, but, in fact, I think
6 that was a very important clue that Georgia Power
7 also felt those actions were imprudent. So the two
8 Hatch events at Hatch 2, we -- we defined as
9 imprudent and should be disallowed.

10 The other events occurred at Vogtle. There
11 were two unit -- two issues at Vogtle 3 and one
12 issue at Vogtle 4, all involving equipment
13 failures. Equipment failures that could have been
14 avoided if the manufacturer, the designer, the OEM,
15 had provided the proper and safe equipment in the
16 first place.

17 We feel that they're imprudent to be put on
18 the backs of the -- in this case, the ratepayers to
19 recover. In fact, there are typically other ways
20 to recover these kinds of losses in utilities, not
21 through the ratepayer. So we concluded that those
22 particular events at Vogtle 3 -- two at Vogtle 3
23 and one at Vogtle 4 were also imprudent and should
24 be declined.

25 MR. COLLADO: Thank you, Mr. Reynolds.

1 Mr. Chairman, the witness is available for
2 questions from the Commission.

3 CHAIRMAN SHAW: Commissioners?

4 (No response.)

5 All right. We'll move on.

6 Georgia Association of Manufacturers.

7 MR. JONES: No questions.

8 CHAIRMAN SHAW: Georgia Interfaith Power &
9 Light and Southface.

10 MS. WHITFIELD: No questions.

11 CHAIRMAN SHAW: MARTA.

12 MR. BAKER: No questions.

13 CHAIRMAN SHAW: Resource Supply Management.

14 (No response.)

15 Sierra Club, SACE, and NRDC.

16 MS. ARIZA: No questions.

17 CHAIRMAN SHAW: All right. Georgia Power
18 Company.

19 MR. HEWITSON: Thank you, Mr. Chairman.

20 CROSS-EXAMINATION

21 BY MR. HEWITSON:

22 Q. Mr. Reynolds.

23 A. Hello.

24 Q. Steve Hewitson on behalf of Georgia Power
25 Company. You have just discussed the Rocky Mountain

1 prudence standard; right?

2 That's the standard that you applied?

3 A. I did for imprudency, yes, sir.

4 Q. Okay. Under that standard, decisions are
5 judged based on what was known or reasonably should have
6 been known at the time without the benefit of hindsight;
7 right?

8 A. That's right.

9 Q. Do you agree that there is a range or a zone
10 of reasonableness to be applied so that a decision can
11 be -- still be prudent even if, in hindsight, another
12 option might look better?

13 A. I would say that there could be that
14 application, but it wouldn't be the one I would use to
15 determine imprudence. It could be that there are the
16 things that were regarding the past.

17 In fact, one of the events at -- at the
18 Hatch -- Hatch plant was related to a situation that had
19 been in existence for 16 years. And certainly hindsight
20 popped right up when that occurred and people then
21 realized they had missed something that should have been
22 caught 16 years before.

23 So there is an issue of hindsight that is
24 relevant to that particular case to review because it
25 indicated a definite history that was then part of the

1 decision on that particular matter as to what its relative
2 position was.

3 Q. Yeah. But that's not really a hindsight
4 review. That's using the fact that something may have
5 been missed multiple times over as a causal factor of why
6 somebody might have been imprudent. That's not using
7 information after the fact to determine that something
8 was -- was imprudent; right?

9 Because that's what the Rocky Mountain
10 standard said.

11 A. Yes.

12 Q. You can't use after-the-fact information to
13 determine something that was imprudent; right?

14 A. You should not. You should -- you should
15 resist doing that, I think, is the point.

16 Q. Okay. And you agree that prudence is not
17 perfection; right?

18 A. No, it's not.

19 Q. It's what a reasonable utility manager would
20 do based on information then available; right?

21 A. It's based on the reasonable man's standard,
22 yes, sir.

23 Q. As you note in your testimony, the standard
24 in fuel cost recovery proceedings is clearly imprudent;
25 right?

1 Illegal or clearly imprudent, but --

2 A. That would be -- yes. My opinion then it's
3 up to the Commission staff to state that to the final
4 point, yes.

5 Q. The Commission or the Commission staff?

6 A. Commission.

7 Q. Thank you. I didn't want to give them too
8 much credit.

9 In your view, to be clearly imprudent there
10 must be a negative pattern or trend and a failure of
11 correct and -- corrective actions to prevent recurrence;
12 right?

13 A. Yes.

14 Q. All right. Do you agree that single isolated
15 events do not typically meet the standard of clearly
16 imprudent?

17 A. Sometimes they don't. I think it's a
18 question of all the issues have to be considered. Every
19 case is different.

20 Q. Okay. And to meet the standard of clearly
21 imprudent, you believe there should be some clear and
22 convincing evidence of imprudence; right?

23 A. Yes.

24 Q. Okay. For your review you relied heavily on
25 condition reports, apparent cause reports, and root cause

1 analyses, which are all written after the events. Is that
2 a fair statement?

3 A. That's fair, yes.

4 Q. Okay. Those -- those documents necessarily
5 reflect information learned after the outage; right?

6 A. Yes.

7 Q. They're written with the benefit of
8 hindsight; right?

9 A. They report on what they found. Some of the
10 events, of course, report what was found at the time of
11 the event or just prior to it.

12 Q. All right. Have you read Mr. Berry's
13 testimony and -- Mr. Earl Berry's rebuttal testimony?

14 A. I have, yes.

15 Q. Okay. And did you see where he explained how
16 the documents, those root cause analyses, apparent cause
17 analyses, condition reports, are deliberately written with
18 a -- to a standard higher than prudence to identify every
19 possible corrective action and opportunities for
20 improvement without regard to cost?

21 A. I've read that, yes.

22 Q. Okay. Do you agree that internal causal
23 analyses are designed for continuous improvement, not to
24 decide whether past decisions were prudent?

25 A. I would say that that is the responsibility

1 of -- of the -- I say utility maintenance staff and
2 management. But that's -- their focus is strictly on
3 preventing the action from happening again.

4 Q. Okay. And in your testimony, you do not
5 identify any methodology that you use to separate
6 hindsight-based information in those reports from what the
7 operators or management actually knew at the time of the
8 incident, do you?

9 A. Well, we always look at -- as I mentioned in
10 my opening statement, the timeline of events is critical.
11 For that reason, we go back as far as necessary to find
12 the origin of the issue. In one case, it was 16 years
13 before the event.

14 On the other hand, we want to know exactly
15 what happened the day of, the day before, perhaps it's a
16 week before leading up to the event. Because, as I
17 mentioned, most incidents are multiple issues, never one
18 point.

19 Q. There's no section in your testimony where
20 you reconstruct for each event which was actually known at
21 the time of the incident and then filter out the hindsight
22 evaluation that you reviewed in the causal reports; is
23 that right?

24 A. We did not -- we did consider every timeline,
25 as I mentioned, from the beginning of the story, which

1 might be a day or two or an hour before, a meeting that
2 took place where there was a, let's say, missed
3 opportunity to put priority issues in place. But those
4 issues have to be considered in the whole as to what
5 happened. So we look at things in a broad-brush look at
6 the event over time.

7 Q. So you're saying you considered both the
8 information that the operator knew at the time of the
9 incident, as well as the hindsight analyses that was --
10 that was presented after the incident?

11 A. If it was relevant. If it was relevant.
12 It's about relevancy.

13 Q. All right. Let's turn to the Hatch Unit 2
14 event in -- the one from 2025. It's on page 16 of your
15 testimony. Or it starts on page 16 of your testimony.

16 This outage occurred during a turbine control
17 valve test; right?

18 A. Yes.

19 Q. Now, you testified that the outage was the
20 result of human error and was avoidable; right?

21 A. Yes, I did.

22 Q. Your reasoning was not the human error
23 itself, but, in your words, clearly imprudent management;
24 is that right?

25 A. It was a combination. A combination. There

1 was a human error factor in the operation itself, and
2 management had failed to provide, I would call it, firm
3 commitment and following the responsibility to look at
4 every factor, rather than one or two factors that were
5 considered to be key or considered to be primary in the
6 process, which was a process failure.

7 There were some things that the operators did
8 not do in the -- in that process that failed, caused
9 the -- the failure itself. And it was the management
10 failing to follow up with all the things that need to be
11 done.

12 There was a little bit of hindsight. What
13 happened before that event occurred? They had to follow a
14 standard. They had to then apply it and failed in the
15 application.

16 Q. Okay. On pages 9 through 11 of your
17 testimony, you list a number of questions -- a bunch of
18 questions that should be evaluated when the -- when
19 determining whether an action was the result of clear
20 imprudence; right?

21 A. I did ask some questions, yes.

22 Q. Okay. And I assume you went through these
23 factors in reaching your conclusions in -- in this case
24 regarding these outages; right?

25 A. Yes.

1 Q. Okay. The first question, which is found on
2 page 9, line 10, asks whether there have been similar or
3 related events in the past; right?

4 A. Yes.

5 Q. Okay. You do not identify in your testimony
6 any prior similar event where this same turbine control
7 valve test caused an outage, do you?

8 A. No, I don't.

9 Q. Okay. You also do not identify any pattern
10 of the same procedural error recurring multiple times;
11 right?

12 A. In the valve failure, no.
13 You're talking about Hatch now?

14 Q. Yes.

15 A. Hatch? Okay. Hatch 2.

16 Q. In fact, we know the opposite is true; right?
17 You're aware that the same operators
18 completed this same test three times before this event
19 occurred; right?

20 A. Yes.

21 Q. So that's the opposite of a pattern of
22 failure, isn't it?

23 A. I wouldn't say that, but it's --

24 Q. Well, if it -- if it was performed
25 successfully three times --

1 A. Yes.

2 Q. -- and then the fourth time was a failure,
3 you can't say that's a pattern of failure, can you,
4 Mr. Reynolds?

5 A. I would say that the -- the pattern that was
6 related to, I think, the decisions made when the
7 discussion about the particular failure event or sequence
8 was somewhat of a pattern because of the way it was
9 conducted.

10 Q. What's the pattern?

11 A. Not prior to. There was no prior indication
12 that that had happened, no.

13 Q. Okay. Yeah. There was no prior indication
14 or no prior pattern of this happening; right?

15 A. No.

16 Q. Okay. When humor -- human error is involved,
17 you ask whether the operator is properly trained; right?

18 A. Yes.

19 Q. You made no finding regarding the training of
20 the operator, do you?

21 A. I did not.

22 Q. Okay. You also ask if the operator had the
23 necessary education, experience, and training to perform
24 the work; right?

25 A. I didn't ask that, no.

1 Q. Oh, you didn't ask that?

2 A. I didn't ask that question about --

3 Q. You didn't ask that question about the
4 operator. That is a question you ask in making these
5 determinations; right?

6 A. It's one of the factors we would look at.

7 Q. Okay. But in this case, you did not ask that
8 question?

9 A. I think it was pretty clear that the failure
10 at Hatch 2 was a gross misapplication of whatever training
11 they had where they did not follow through on recognizing
12 all the primary issues in the -- in the sequence to make
13 sure that they were -- were reviewed and stopped. They
14 have a pause that is put in place to review to make sure
15 that the next step is going to be done right.

16 They failed to do that.

17 Q. Well --

18 A. And that seems to me to be beyond the
19 question of training. It seems to be a mistake made
20 whether -- whatever training they got, they did not apply
21 it at that time.

22 Q. It's really hard for me to follow you when
23 you say it's a gross misapplication of procedures when we
24 just discussed how these individuals had just completed
25 that test successfully three times.

1 A. That may be the case. That happens all the
2 time. People work in a -- in a particular environment
3 that do fine for years and years, and then, finally, one
4 day, they make a terrible mistake. This is that day.

5 Q. Okay. But what -- your questions that you
6 ask in determining prudence go into the training of
7 someone, the education of someone, the experience of
8 someone. And your testimony makes no finding about the
9 operator's training, experience, or education; right?

10 A. If the situation was different, I may have
11 looked into that very carefully. But there was no reason
12 shown in the sequence of the story about the failure that
13 indicated to me that the training was the problem. It was
14 more than that.

15 Q. Okay. You ask if the procedure -- in
16 determining whether something's imprudent, you ask if the
17 procedures were correct and adequate; right?

18 A. Yes.

19 Q. You did not reach any conclusion in your
20 testimony that the procedures were inadequate; right?

21 A. I did not.

22 Q. Okay. And, in fact, the root cause analyses
23 that you reviewed also did not find the procedures to be
24 inadequate; is that correct?

25 A. No. It simply said the cause was human

1 error.

2 Q. Okay. And you are not claiming that the
3 written procedure was unreasonable for an experienced
4 operator at the time; right?

5 A. I did not reach that conclusion, no.

6 Q. Your next question when you're determining
7 prudence is whether the procedures were followed, which
8 obviously we know they were not; right?

9 A. Correct. Yes.

10 Q. But we know they were followed three times
11 before it happened. So we know the answer to the next
12 question, which is: Would the procedures result in proper
13 and prudent operation; right?

14 The answer to that is yes?

15 A. If followed correctly, yes.

16 Q. Okay. So you have a one-time event here with
17 no pattern of recurrence; right?

18 It hasn't happened since, to your knowledge?

19 A. To my knowledge, I don't know. I hope not.

20 Q. Okay. And the -- the procedures were
21 appropriate. And had they been followed, would have
22 success -- would have resulted in successful completion of
23 the task; right?

24 A. Yes.

25 Q. And you made no finding that the operator was

1 improperly trained or that he lacked the education or
2 experience to complete the task, do you?

3 A. No.

4 Q. Okay. Let's move on to the Hatch 2 outage in
5 2023, the reactor feed pump drain line outage.

6 Your conclusion is that this outage was
7 avoidable on numerous occasions I think was your language;
8 right?

9 A. That's correct.

10 Q. Okay. You testify on page 21, lines 20 to
11 21, that, quote: Plant personnel failed to understand and
12 resolve repeated failures of the defective drain line
13 support system, end quote.

14 Do you see that testimony?

15 A. Yes, I have. Yes.

16 Q. Well, you're aware --

17 A. I'm aware of it.

18 Q. -- you wrote it?

19 A. I wrote it, yes.

20 Q. That's fair enough.

21 The root cause report you cite notes that a
22 bracket was installed in the wrong place in 2007; right?

23 A. Yes.

24 Q. And this eventually led to a fatigue failure
25 in 2023; right?

1 A. Yes.

2 Q. And while there were some vibration concerns
3 over the years, there was no failure of the equipment that
4 caused an outage until 16 years later; right?

5 A. There was no outage, but there were bracket
6 failures repeatedly over that time and were replaced
7 numerous occasions.

8 Q. Okay. But before November 2023, the
9 information that management had was that broken brackets
10 could be repaired. There was no line failure or outage
11 for 16 years.

12 Is that a fair statement?

13 A. Not because of that, no.

14 Q. Okay. That was the contemporaneous record
15 from 2007 to 2023; right?

16 A. Correct.

17 Q. Okay. Your conclusion seems to be that the
18 company should have recognized a more fundamental design
19 issue, which depends heavily on the later knowledge
20 provided in the post-event roots -- root cause analysis,
21 doesn't it?

22 A. Yes.

23 Q. Okay. You do not identify any
24 contemporaneous information that clearly shows an
25 experienced nuclear maintenance organization was acting

1 unreasonably between 2027 -- I'm sorry -- 2007 and 2023,
2 when it repaired those brackets and monitored the
3 situation, do you?

4 A. I do. I think that's my finding is that they
5 should have recognized that vibrations in -- in a nuclear
6 plant in particular are very, very serious and should be
7 taken seriously, particularly on these kinds of -- this is
8 a piping that is critical to the operation of the reactor.

9 Q. Okay. Do you identify --

10 A. There's -- there's a reason --

11 Q. Oh, I'm sorry.

12 A. There's a reason -- if I can explain a little
13 further.

14 Q. Uh-huh.

15 A. If -- there's a reason. If the vibration is
16 so severe that it is causing multiple failures of bracket
17 holders or retention devices which hold that -- what we
18 might call a drain line in place and are connected to that
19 piece of metal that broke -- it's a small 1-inch diameter
20 piece of pipe attached to a larger 11-inch diameter pipe.
21 It's there to drain. And it was vibrating so much that it
22 broke the -- the holder or the clamp that was holding it
23 in place over -- repeatedly over those years.

24 A person of some knowledge -- and this is why
25 I was concerned about it. That it didn't get reported

1 because something like that should be reported -- or
2 noticed that repeat failures is an obvious red star.
3 Something's not right. You've got to find out what it is
4 and fix it right. Because it's can't -- you can't have a
5 repeat failure like that over and over and over again.

6 I've -- I've spent a lot of time in plants
7 and -- and the personnel are usually very quick to
8 recognize something like that as a potential failure that
9 could cause the pipe to break, which it did. It break --
10 broke and separated from the larger pipe. And that then
11 resulted in the outage.

12 Q. But the one and only outage that was caused
13 by this pipe failure was in 2023; right?

14 A. That's when it -- that's when the pipe
15 failed, yes. It ultimately failed, but it was probably in
16 a mode of failure for years before.

17 Fatigue failure was probably happening. That
18 means it was suffering from this vibration for a long time
19 and just finally went, if you will, in '23.

20 Q. Okay. Let's -- let's move over to Vogtle,
21 the Unit 3 outage in September of 2024.

22 It was caused by a premature failure of a
23 piece of equipment, which is referred to as a single point
24 vulnerability; right?

25 A. Yes.

1 Q. Okay. And I'm trying not to use trade secret
2 information, but I'm glad that you're on the same page
3 with me of which outage we're at.

4 A. I would -- I know what you mean.

5 Q. Appreciate that.

6 In your testimony on page 22, line 19, you
7 expressly acknowledged the company could not have avoided
8 this forced outage; right?

9 A. Correct.

10 Q. Rather, your -- your criticism focuses on the
11 design being a single point of vulnerability and on the
12 equipment being classified as run-to-maintenance, rather
13 than critical component; right?

14 A. That's correct.

15 Q. This equipment configuration is part of the
16 AP1000 design; is that correct?

17 A. That is correct.

18 Q. And you understand that under 10 CFR Part 52,
19 the company could not have made changes to the design
20 without NRC approval; right?

21 A. Absolutely.

22 Q. Okay.

23 A. Yes.

24 Q. The classification of the equipment as
25 critical component would not have changed the maintenance

1 for this -- this equipment, would it have?

2 A. It really wasn't a maintenance issue. It was
3 a design issue.

4 Q. Right.

5 A. Yes.

6 Q. Yeah. But --

7 A. Right.

8 Q. -- my question is: Run to --
9 run-to-maintenance or critical component doesn't change
10 the way you treat the component -- the piece of equipment
11 once it's installed?

12 This particular piece of equipment.

13 A. This particular piece of equipment, it would
14 not necessarily. It is a question about maintenance
15 because of the nature of the failure, which now, of
16 course, there was a redesign.

17 I think it's still waiting to be certified or
18 approved by the NRC, but by the OEM, realized that they
19 should not have had this as a critical point of -- single
20 point of failure and they're changing the algorithm, as
21 you would call it, or the control circuitry -- the
22 computer circuitry that controls the outage and will be
23 installing that in the near future.

24 Q. Okay. And according to EPRI recommendations,
25 this equipment that we're talking about is designated as a

1 single point vulnerability and scheduled for replacement
2 no later than ten years; right?

3 A. That would be the case, yeah. And EPRI now
4 getting another standard, another group. They look at
5 fuses as having a -- a life. And normally you think of a
6 fuse as having a -- not a -- not a -- a permanent life, a
7 shelf life of maybe ten years, or an operational life.

8 In this case, the other thing that was an
9 issue was this was a run-to-maintenance fuse or type,
10 which means it runs to failure. You replace it when it
11 fails. And that's, like, on a home fuse. You go down in
12 the cellar and you go down and replace a fuse or a circuit
13 breaker today. But it would not be replaced until it
14 failed.

15 Now, the new requirement would be that it's
16 a -- a critical item. A critical item that has to be
17 examined and maybe examined to the point of testing. If
18 there are multiple of these, you need to make sure they're
19 still functioning or they're properly set to fail when
20 necessary.

21 But a fuse is always a one-time event. It
22 just goes and that's gone. So you have to be prepared for
23 if lost -- a sudden loss.

24 Q. And at the time of the failure, the equipment
25 was less than ten years old; right?

1 A. Yes, it was less.

2 Q. In fact, it was less than a year old, wasn't
3 it?

4 A. It was, yes.

5 Q. The company had replaced all of these pieces
6 of equipment after construction was completed and before
7 commercial operation began; right?

8 A. They went through a process of examining the
9 fuses that were contemplated and they -- by x-ray and
10 other means. And they were replaced by another brand.
11 But they were still a run-to- -- run-to-maintenance item
12 at the time of the failure.

13 Q. The equipment was installed pursuant to the
14 NRC-approved design; right?

15 A. Yes.

16 Q. And the company followed EPRI maintenance
17 guidance and, in fact, did more than EPRI recommends; is
18 that right?

19 A. Yes. I think -- well, they were following
20 NRC. EPRI is not the ultimate. So NRC is.

21 Q. Right.

22 A. They were following what NRC required.

23 Q. Is there a specific realistic alternative
24 action consistent with NRC and industry standards
25 reasonably knowing beforehand that you believe the company

1 should have taken to avoid this outage?

2 A. To avoid the outage? No. I don't think they
3 would have -- they would have known. It was unknown.
4 This was a true design error, which only occurred when --
5 when the failure occurred.

6 Q. All right. Let's flip over to the other
7 Unit 3 outage. This one was July of 2024.

8 A. Right.

9 Q. In your -- your conclusion is that the
10 manufacturer was imprudent by allowing a defective piece
11 of equipment to be installed; is that right?

12 A. The question was a matter of debris being in
13 a valve, which caused it to fail and then trip the -- led
14 to the tripping of the -- of the unit. And that material
15 was shown by Georgia Power very clearly that it had to be
16 there when it was installed in the plant. That they had
17 never opened this valve for any kind of maintenance and
18 that the foreign material, which had caused the problem,
19 what had to have been installed or, let's say, inserted or
20 found its way into the valve, and not sure how it got
21 there, at the time of manufacture.

22 So that again comes back to responsibility
23 of, this case, the hardware manufacturer, the valve
24 manufacturer.

25 Q. Right. And you don't contend -- you do not

1 contend -- should be clearer -- that the company had any
2 knowledge that this equipment was defective when it was
3 installed; right?

4 A. No, I don't. They did not know about it.

5 Q. And you -- and there's no way, because you
6 don't open these valves during regular maintenance --
7 there's no way for them to have figured it out; right?

8 A. No. They wouldn't have known.

9 Q. Okay. On -- going back to page 10, you do
10 list a bunch of prudence factors for equipment failures --
11 right? -- in your testimony that you look at when the
12 issue is an equipment failure?

13 A. Yes. Yes.

14 Q. Okay. Do you contend that there have been
15 any similar -- or any -- any equipment failures similar to
16 this incident -- incident at the plant before?

17 A. Similar as a contaminated valve?

18 Q. Yeah.

19 A. I don't know of any other contaminated
20 valves, no.

21 Q. Okay. And do you contend that the company
22 failed to take steps to prevent or mitigate subsequent
23 equipment failures of this type?

24 A. No, I'm not aware of any.

25 Q. Do you contend that the company failed to

1 perform prior maintenance in a timely manner?

2 A. On these valves? Not that I know of, no.

3 Q. Do you contend that there is any preventative
4 maintenance that could have prevented this specific piece
5 of equipment from failing?

6 A. Other than what they finally did when it
7 failed was to open it up and find the problem, but they
8 would have no reason to do that.

9 Q. Okay. And there were no prior indications
10 that this particular valve had debris in it and it was
11 going to fail; right?

12 A. No, there weren't, as far as I know.

13 Q. Okay. All right. The last outage is Vogtle
14 Unit 4, the June of 2024. And you conclude that the
15 installation vendors were imprudent in the selection and
16 installation of the equipment at issue; right?

17 A. Yes.

18 Q. And you do not allege that the company was
19 imprudent in any decision or action that it took; is that
20 right?

21 A. That's correct.

22 Q. You do not testify that the company acted
23 unreasonably in any way with this outage; is that right?

24 A. This is another one of the -- as I mentioned
25 in my opening statement, the three OEM, or, in this case,

1 vendor issues that's with a contractor who had installed
2 wiring for sensors that control valves in emergency
3 situations for over-temperature situations. And they had
4 used improper connectors and terminals when it was
5 installed, which failed. The wires actually fell off of
6 the terminal because it did not have the proper latching
7 mechanism required by design. And that was the ultimate
8 cause.

9 So it's again -- and this happened -- wasn't
10 it just -- you mentioned timing. This was 36 days after
11 the plant went into operation. 36 days. Barely a month
12 when this failed.

13 So this is what you'd call -- infant syndrome
14 we call it. A very early failure when something is so
15 wrong. It didn't last more than a month, if that.

16 So here's a case where truly the need is to
17 go back to the construction company, the designers, or
18 whoever selected and installed this equipment would be
19 responsible for any cost. I realize that there are a lot
20 of warranty issues. There is no coverage for this sort of
21 thing. But there are other ways -- other ways that
22 utilities over the years I know well have found a means to
23 recover losses.

24 MR. HEWITSON: Thank you, Mr. Reynolds.

25 That's all I have for you.

1 MR. REYNOLDS: Thank you very much.

2 CHAIRMAN SHAW: Redirect?

3 MR. COLLADO: No redirect, Mr. Chairman.

4 I would just ask that the witness be excused

5 and his testimony be entered into the record as STF

6 Exhibit 2.

7 CHAIRMAN SHAW: So marked.

8 (The document referred to was marked for

9 identification as PIA Staff Exhibit 2.)

10 CHAIRMAN SHAW: Mr. Reynolds, thank you for

11 being with us. Thank you --

12 MR. REYNOLDS: My pleasure.

13 CHAIRMAN SHAW: -- for all your work on

14 behalf of the Commission.

15 MR. REYNOLDS: Thank you, sir.

16 CHAIRMAN SHAW: You can be excused.

17 MR. REYNOLDS: Okay.

18 CHAIRMAN SHAW: And I'll let Mr. Jones start

19 his way up and swear in Mr. Pollock.

20 Mr. Pollock, good to have you with us.

21 MR. POLLOCK: Thank you. Good to be here.

22 CHAIRMAN SHAW: Are you good to move on right

23 now?

24 MR. JONES: I'm -- I'm ready whenever you

25 are.

1 CHAIRMAN SHAW: Okay.

2 MR. JONES: Yes, sir.

3 You ready, Mr. Pollock?

4 MR. POLLOCK: Yeah.

5 MR. JONES: All right. Raise your right

6 hand.

7 Thereupon,

8 JEFFRY POLLOCK,

9 having been duly sworn, testified as follows:

10 DIRECT EXAMINATION

11 BY MR. JONES:

12 Q. All right. Could you please state your name.

13 A. Jeffry Pollock.

14 Q. And, Mr. Pollock, how are you employed, sir?

15 A. I am the president of J. Pollock,

16 Incorporated.

17 Q. Okay. And have you testified before this

18 Commission in the past?

19 A. I have.

20 Q. How many times?

21 A. I can't count.

22 Q. For many years; right?

23 A. Well, I think -- I recall being here in the

24 late '70s, but I won't say any more because I don't want

25 to give away too much.

1 Q. Yeah. All right. Thank you.

2 On whose behalf are you testifying today?

3 A. Georgia Association of Manufacturers.

4 Q. All right. And on April 9th of this year,
5 did you file or cause to be filed in this docket 26 pages
6 of written question-and-answer testimony, which includes
7 two appendices?

8 A. Yes.

9 Q. Do you have any changes you need to make to
10 your testimony today?

11 A. No.

12 Q. Okay. With -- if I were to ask you the same
13 questions that appear in your testimony, would your
14 answers be the same?

15 A. Yes.

16 MR. JONES: Mr. Chairman, I ask the witness's
17 testimony to be placed into the record as if orally
18 presented from the stand.

19 CHAIRMAN SHAW: Yep. So marked.

20 (Whereupon, the prefiled direct testimony
21 of Jeffry Pollock follows:)

22

23

24

25

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

**In Re:
Georgia Power Company's
Fuel Cost Recovery FCR-27**

)
)
)

Docket No. 56765

Testimony & Exhibit

of

Jeffry Pollock

On Behalf of

Georgia Association of Manufacturers

April 9, 2026



J . P O L L O C K
I N C O R P O R A T E D

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
Georgia Power Company's	)	Docket No. 56765
Fuel Cost Recovery FCR-27	)	

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Exhibit	Description
JP-1	Henry Hub Natural Gas Spot Price

GLOSSARY OF ACRONYMS

Term	Definition
ARP	Annual Rate Plan
FCR	Fuel Cost Recovery
GAM	Georgia Association of Manufacturers
GPC	Georgia Power Company
IFR	Interim Fuel Recovery
kWh	Kilowatt-Hour(s)
PTC	Production Tax Credit
RFP	Request for Proposal

DIRECT TESTIMONY OF JEFFRY POLLOCK

1 **Introduction, Qualifications and Summary**

2 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A Jeffry Pollock; 14323 South Outer 40 Rd., Suite 206N, St. Louis, MO 63017.

4 **Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

5 A I am an energy advisor and President of J. Pollock, Incorporated.

6 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

7 A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in
8 Business Administration from Washington University in St. Louis, Missouri. Since
9 graduation in 1975, I have been engaged in a variety of consulting assignments,
10 including energy procurement and regulatory matters in both the United States and
11 several Canadian provinces. My qualifications are documented in **Appendix A**. A list
12 of my appearances is provided in **Appendix B** to this testimony.

13 **Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

14 A I am testifying on behalf of the Georgia Association of Manufacturers (GAM). The
15 members of GAM are customers of Georgia Power Company (GPC). They consume
16 large quantities of electricity, primarily for manufacturing, under a variety of rate
17 schedules.

18 **Q WHAT ISSUES ARE YOU ADDRESSING IN YOUR DIRECT TESTIMONY?**

19 A First, I present an overview of GPC's proposed Fuel Cost Recovery- (FCR-27) rate
20 proposal. I will then discuss GPC's proposal to expand its natural gas hedging
21 program. Finally, I address why nuclear production tax credits (PTCs) authorized

1 under section 45U of the Internal Revenue Code should be used to offset FCR-27
2 costs rather than storm damage costs.

3 **Q DOES THE FACT THAT YOU ARE NOT ADDRESSING ALL ISSUES IN THIS**
4 **PROCEEDING CONSTITUTE AN ENDORSEMENT OF THE POSITIONS OF**
5 **GEORGIA POWER COMPANY OR OTHER PARTIES ON THESE ISSUES?**

6 A No. The fact that I am not addressing every issue should not be interpreted as an
7 endorsement of GPC's or other parties' proposals in this proceeding.

8 **Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?**

9 A Yes. I am sponsoring **Exhibit JP-1**.

10 Summary

11 **Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

12 A My findings and recommendations are as follows:

- 13 • GPC is proposing to concurrently reduce fuel cost recoveries while
14 increasing base revenues, effective June 1, 2026. The proposed FCR-27
15 would reduce fuel revenues by \$388 million (12.5%). This reduction would
16 be partially offset by GPC's storm damage recovery proposal, which would
17 increase annual revenues by \$270 million.
- 18 • GPC is also proposing:
 - 19 ○ To continue and expand its natural gas hedging program;
 - 20 ○ To increase the threshold under the Interim Fuel Recovery (IFR)
21 mechanism from \$200 million to \$300 million; and
 - 22 ○ To continue recovering through the FCR all renewable requests for
23 proposal (RFPs) and renewable subscription program-related costs
24 that are not otherwise recovered through bid fees and winner's fees.
- 25 • GPC has not demonstrated that its natural gas hedging program is
26 providing actual benefits to customers despite the significant costs
27 incurred. Accordingly, the Commission should reject GPC's proposal to
28 expand gas hedging until tangible benefits can be demonstrated.

- GPC is proposing to use \$90 million of section 45U nuclear PTCs to offset \$360 million of storm damage expense. These tax credits were generated in 2024 and 2025.
- PTCs are earned for every kilowatt-hour (kWh) generated from eligible nuclear production facilities, which include GPC's Hatch and Vogtle units 1 and 2. Thus, these PTCs more closely resemble fuel costs than storm damage expenses.
- Using PTCs as an offset to storm cost recovery would not be consistent with cost causation because (pursuant to the Settlement Agreement approved in the Annual Rate Plan (ARP) extension) they would be allocated to customer classes on base revenues.
- A more reasonable and cost-based approach is to use the nuclear PTCs to offset FCR-27 recoverable fuel costs. Therefore, the Commission should use these tax credits to offset recoverable FCR-27 costs.

Overview

Q WHAT CHANGE IN FCR RATES IS GEORGIA POWER COMPANY PROPOSING IN THIS APPLICATION?

A The proposed FCR-27 would reduce fuel revenues by \$388 million (12.5%).¹ This would result in a revenue reduction of approximately 3.3%. The proposed change in fuel rates is summarized in Table 1. The primary driver for the fuel cost reduction is a significant decrease in the past period under-collection balance, which has decreased from \$2.2 billion to \$310 million. GPC is also projecting a 3.5% increase in net recoverable fuel costs during the FCR-27 test period of June 2026 through May 2028. The increase is largely being driven by higher projected natural gas prices.

¹ Direct Testimony of Adam D. Houston and Matthew S. Berrigan at 5.

Table 1 Comparison of FCR-26 and FCR-27 Rates by Delivery Voltage (per kWh)				
Delivery Voltage	FCR-26	FCR-27	Change	% Change
Summer				
Transmission	4.4741¢	3.7214¢	-0.7527¢	-16.8%
Primary	4.5055¢	3.7475¢	-0.7580¢	-16.8%
Secondary	4.5877¢	3.8158¢	-0.7718¢	-16.8%
Non-Summer				
Transmission	4.1798¢	3.7700¢	-0.4098¢	-9.8%
Primary	4.2092¢	3.7965¢	-0.4127¢	-9.8%
Secondary	4.2859¢	3.8657¢	-0.4202¢	-9.8%
Sources: FCR 26 and Exhibit (ADH/MSB-5).				

1 **Q IS GEORGIA POWER COMPANY PROPOSING OTHER REQUESTS IN THIS**
2 **PROCEEDING?**

3 **A Yes.** First, GPC is proposing to expand its hedging program to include up to 60% of
4 budgeted natural gas burn for a period of up to 48 months. Currently, GPC is allowed
5 to hedge 40% of budgeted natural gas burn for a period of up to 36 months.²

6 Second, GPC is proposing to increase the threshold under the IFR mechanism
7 from \$200 million to \$300 million.³

8 Finally, GPC requests continued authorization to recover through the FCR all
9 renewable RFPs and renewable subscription program-related costs that are not
10 otherwise recovered through bid fees and winner's fees.⁴

² *Id.* at 21.

³ *Id.* at 22.

⁴ *Id.* at 24.

1 **Q IS THIS THE ONLY PENDING APPLICATION THAT WILL IMPACT RETAIL**
2 **RATES?**

3 A No. Concurrently, GPC made a second filing to increase annual revenues by \$270
4 million (5.0%) to recover expenses associated with major storms that occurred since
5 the Company's 2022 base rate case (Docket No. 44280). Recovery would occur over
6 a four-year period, and GPC would earn its authorized weighted average cost of
7 capital, including a 10.5% return on common equity, on the unamortized balance. The
8 \$270 million includes \$360 million of incremental storm costs, which GPC is proposing
9 to partially offset by using \$90 million of nuclear PTCs earned in the years 2024 and
10 2025.⁵

11 Together, the two filings would result in a net \$118 million (1.0%) reduction in
12 overall rates (\$388 million less \$270 million). The FCR and storm cost recovery rates
13 are proposed to become effective June 1, 2026.⁶

14 **Q DO GEORGIA POWER COMPANY'S APPLICATIONS RAISE IMPORTANT**
15 **POLICY ISSUES?**

16 A Yes. As previously stated, the Company is proposing to continue, and expand, its
17 natural gas hedging program. This raises the question of whether it is both necessary
18 and beneficial for GPC to engage in natural gas hedging to help "stabilize" fuel costs.

⁵ *In Re: Georgia Power Company's Storm Damage Recovery Application*, Docket No. 44280, Direct Testimony of Cleve L. Fann, Josh J. Stallings, and Matthew S. Berrigan, Exhibit___(CLF/JJS/MSB), Pg. 1 (Feb. 17, 2026).

⁶ *Id.* at 27; Direct Testimony of Adam D. Houston and Matthew S. Berrigan at 7.

1 Second, GPC is proposing to use nuclear PTCs to make the proposed storm
2 recovery charges more affordable for consumers. However, as discussed later,
3 nuclear PTCs are no different in nature from recoverable fuel expenses. Both are
4 related to kWh generation. Whether the nuclear PTCs are used to offset storm
5 damage costs or to lower the FCR rate, GPC's customers would still benefit and rates
6 would be more affordable. However, using the nuclear PTCs to offset the FCR
7 balance would be consistent with cost causation.

8 **Natural Gas Hedging**

9 **Q WHAT IS A HEDGE?**

10 A In general, a hedge refers to a financial transaction that aims to mitigate exposure to
11 market price volatility. Within the context of natural gas markets, a hedge represents
12 a financial position in gas futures contracts that can offset potential losses (or gains)
13 incurred by fluctuations in the natural gas commodity price. That stated, natural gas
14 hedging can protect the utility from upside price risk if market prices at the time of
15 delivery are higher than the hedged price, but it can also expose the utility to losses if
16 the market price settles below the hedged price.

17 **Q WILL A HEDGING STRATEGY RESULT IN BELOW-MARKET FUEL COSTS?**

18 A No, not necessarily. A proper hedging strategy means managing price risk and not
19 entering into speculative transactions to beat the market. Over time, hedging should
20 result in a utility purchasing fuel at the market price (plus reasonable transaction and
21 administrative costs) but with much less volatility. As discussed later, this expected
22 result has not materialized for GPC.

1 **Q IS NATURAL GAS HEDGING COST-FREE?**

2 A No. First, GPC will incur its own costs to develop hedging strategies and to procure
3 and manage its fuel hedges. Second, GPC will incur fees to execute various financial
4 instruments (*i.e.*, swaps and collars). Third, because financial swaps lock-in the price
5 of natural gas for specific quantities and time periods, GPC may incur either gains or
6 losses if a specific swap settles above or below the current market price, respectively.

7 **Q WHY IS GEORGIA POWER COMPANY ENGAGED IN NATURAL GAS HEDGING?**

8 A GPC's gas hedging program was implemented in response to the increasing volatility
9 of natural gas prices, as well as its growing reliance on natural gas generation.

10 **Q ARE NATURAL GAS PRICES ALWAYS VOLATILE?**

11 A No. However, natural gas prices do react to major storms and geopolitical events.
12 **Exhibit JP-1** provides a history of spot natural gas prices traded at the Henry Hub
13 since 1997. Also shown are the major events that triggered spikes in gas prices. As
14 can be seen, the most extreme price spikes occurred during Winter Storm Uri in
15 February 2021 and, more recently, Winter Storm Fern in January 2026. Both storms
16 featured severe snow and ice and sustained below-normal temperatures.

17 Given the history, while an active hedging program could help to manage
18 volatility, it is reasonable to question whether customers directly benefit when the utility
19 executes hedges to stabilize natural gas prices.

20 **Q DID THE COMMISSION PREVIOUSLY ADJUST GEORGIA POWER COMPANY'S**
21 **GAS HEDGING PROGRAM?**

22 A Yes. In FCR-25, GPC agreed to reduce the hedge window from 48 months to 36
23

1 months and reduce the limit from 50% to 40% of budgeted natural gas burn
2 recognizing, in part, lower relative price volatility.⁷

3 **Q HAVE RETAIL CUSTOMERS CLEARLY BENEFITTED FROM GEORGIA POWER**
4 **COMPANY'S FUEL HEDGING STRATEGIES?**

5 A No. Although the primary objective of hedging is to mitigate fuel price volatility, it is
6 unclear whether this has translated into less volatile retail electricity prices. This, in
7 large part, recognizes the long-standing ratemaking practices used by the Commission
8 to set and periodically review GPC's FCR rates, which facilitate rate stability.

9 **Q DOES FUEL HEDGING GUARANTEE THAT RETAIL ELECTRICITY PRICES WILL**
10 **BE LESS VOLATILE?**

11 A No. Reducing the volatility of fuels acquired by GPC to generate electricity does not
12 necessarily translate into less price volatility for GPC's customers.

13 **Q HAS GEORGIA POWER COMPANY PROVIDED EVIDENCE THAT ITS PAST FUEL**
14 **HEDGING PROGRAMS HAVE RESULTED IN LESS VOLATILE RETAIL**
15 **ELECTRICITY PRICES?**

16 A No.

17 **Q IS FUEL HEDGING THE ONLY TOOL AVAILABLE TO MITIGATE ELECTRICITY**
18 **PRICE VOLATILITY?**

19 A No. The Commission's rate setting practices can also mitigate volatility in both natural
20 gas and other fuel commodity markets. For example, the Commission sets GPC's

⁷ GPC Response to STF-JKA-2-5.

1 FCR rates using a 24-month test period. This helps to smooth any monthly or quarterly
2 variation in natural gas prices that may occur within a calendar year. Should there be
3 a material change in gas prices (either up or down) resulting in an accumulated
4 balance that exceeds \$200 million, GPC can implement an IFR that would absorb
5 unanticipated short-term changes in natural gas and other commodity costs, while not
6 creating substantial price volatility. Finally, any remaining actual over- or under-
7 collected costs can be recovered when setting the next FCR rate.

8 Together, setting a two-year FCR rate, coupled with the IFR and carrying
9 forward past-period balances smooths the impact of changes in natural gas and other
10 commodity prices on retail electricity prices. These effective mechanisms reduce fuel
11 volatility and are sufficient to address fuel price swings. Hedging to further address
12 volatility may be unwarranted given that GPC's hedging programs increased
13 recoverable fuel costs by \$274 million from 2023 through 2025.⁸ Further, during this
14 period, hedging losses occurred in all but one month. An effective hedging program
15 should track market prices over the long term. Thus, it is not unreasonable to expect
16 that hedging losses would be offset by hedging gains.

17 **Q HAVE ANY UTILITIES DISCONTINUED THE GAS HEDGING PROGRAMS**
18 **BECAUSE THEY RESULTED IN SIGNIFICANT HEDGING LOSSES?**

19 **A** Yes. The investor-owned utilities in Florida previously engaged in gas hedging
20 programs since 2002. However, these hedging programs increased recoverable fuel
21 costs by nearly \$7 billion through 2016. As a result of these huge costs, these utilities
22 no longer engage in hedging.

⁸ MFRH-10 Attachment TS.

1 **Q WHAT DO YOU RECOMMEND?**

2 A GPC is ultimately responsible for managing all of its costs, fuel included, in a prudent
3 manner. At times, this may require hedging to better manage commodity risk.
4 However, before allowing GPC to expand its current gas hedging program, the
5 Commission should require GPC to document and quantify how its past hedging
6 strategies have benefitted retail customers.

7 **Nuclear PTCs**

8 **Q WHAT ARE THE NUCLEAR PRODUCTION TAX CREDITS?**

9 A Section 13105 of the Inflation Reduction Act of 2022 created section 45U, the zero-
10 emission nuclear power production credit, for electricity produced at a qualified nuclear
11 power facility and sold by the taxpayer to an unrelated person in tax years beginning
12 after December 31, 2023, and before January 1, 2033.

13 **Q WHAT NUCLEAR POWER FACILITIES QUALIFY FOR THE INTERNAL REVENUE**
14 **CODE SECTION 45U PRODUCTION TAX CREDITS?**

15 A To qualify, a nuclear power facility must have been placed in service before August
16 16, 2022. This means that GPC's Hatch and Vogtle units 1 and 2 potentially qualify to
17 earn section 45U tax credits.

18 **Q HOW ARE PRODUCTION TAX CREDITS EARNED?**

19 A PTCs are earned for every kWh generated by a qualified nuclear power facility.

20 **Q DO PRODUCTION TAX CREDITS REDUCE A UTILITY'S COST TO SERVE?**

21 A Yes. PTCs can be used to reduce the utility's tax liability. If the utility does not have
22 a sufficient tax liability to utilize the PTCs, the utility can monetize the PTCs by selling
23 them to third parties and use the proceeds to reduce costs.

1 **Q HOW IS GEORGIA POWER COMPANY PROPOSING TO UTILIZE THE NUCLEAR**
2 **PRODUCTION TAX CREDITS?**

3 A In its storm damage filing (Docket No. 44280), GPC is proposing to amortize 25% of
4 the total PTCs generated in 2024 and 2025 to partially offset and lower storm damage
5 costs. GPC had originally proposed to defer these PTCs to a regulatory liability and
6 amortize them over a three-year period beginning on January 1, 2026. However, to
7 address affordability, GPC decided to use the section 45U PTCs to benefit customers.⁹

8 **Q SHOULD THE NUCLEAR PRODUCTION TAX CREDITS BE USED TO OFFSET**
9 **STORM DAMAGE EXPENSE?**

10 A No. First, as previously stated, the nuclear PTCs are earned for every kWh generated
11 by a qualified nuclear power facility. Thus, PTCs are clearly more similar to fuel costs,
12 which vary based on the amount of kWh generated, than to storm damage costs.

13 Second, if PTCs are used to offset storm damage costs, the benefit would not
14 be allocated properly. This is because, under the Settlement Agreement approved in
15 ARP Extension, storm damage costs are to be allocated and recovered on equal
16 percentage of base revenues.¹⁰ However, the percentage of base revenues charged
17 to the various customer classes is quite different from the corresponding percentage
18 of recoverable fuel costs. The differences are illustrated in Table 2.

⁹ Docket No. 44280, *Direct Testimony of Cleve L. Fann, Josh J. Stallings, and Matthew S. Berrigan* at 28-29 (Feb. 17, 2026).

¹⁰ *Id.*, *Order Granting Joint Petition of Georgia Power Company and the Public Interest Advocacy Staff and Approval of The Stipulation to Extend The Alternative Rate Plan*, Attachment 1, paragraph 3 (Jul. 31, 2025).

Table 2 Percentage of Base Revenues vs. Percentage of Recoverable Fuel Costs By Customer Class		
Customer Class	Base Revenues	Fuel Revenues
Residential	48.35%	36.85%
Commercial	36.53%	37.24%
Industrial	13.13%	24.95%
Lighting	1.98%	0.95%
Total Retail	100.00%	100.00%
Source: Docket No. 44820, Georgia Power Company Cost-of-Service Study for Test Year Ending July 31, 2023, Schedule 2.00, lines 1 and 2.		

1 **Q PLEASE EXPLAIN TABLE 2.**

2 A Table 2 quantifies the percentage of base revenues and the percentage of fuel
3 revenues by customer class as presented in the class cost-of-service study filed by
4 GPC in its 2022 rate case.

5 **Q WHAT DO YOU CONCLUDE FROM TABLE 2?**

6 A Table 2 demonstrates that Residential customers have a higher percentage of base
7 revenues than fuel revenues, while the opposite is true for Industrial customers. This
8 reflects the fact that Industrial customers typically operate at higher load factors than
9 either Residential or Commercial customers.

10 Thus, using the nuclear PTCs to offset the FCR-27 costs is consistent with cost
11 causation because these tax credits are earned on a kWh basis, and fuel costs are
12 also directly related to the amount of kWh generated.

1 **Q WOULD GEORGIA POWER COMPANY’S NET REVENUES BE THE SAME IF THE**
2 **NUCLEAR PRODUCTION TAX CREDITS ARE USED TO REDUCE THE FUEL**
3 **COST RECOVERY BALANCE RATHER THAN TO OFFSET STORM DAMAGE**
4 **EXPENSE?**

5 A Yes.

6 **Q IS THERE ANY PRECEDENT IN GEORGIA FOR USING NUCLEAR PRODUCTION**
7 **TAX CREDITS AS AN OFFSET TO FUEL COST RECOVERY?**

8 A No. Section 45U became effective after the 2022 rate case. Thus, there has been no
9 prior determination of how nuclear tax credits should be treated for ratemaking
10 purposes.

11 **Q DOES THE FCR RATE PRECLUDE CREDITING THE NUCLEAR PRODUCTION**
12 **TAX CREDITS THROUGH FUEL RATES?**

13 A No. The definition of fuel costs in the FCR-26 tariff includes:

14 (9) other costs or credits as determined by the Commission for inclusion in, or
15 *reduction of*, recoverable fuel costs.¹¹

16 Clearly, nuclear PTCs will reduce recoverable fuel costs.

17 **Q ARE THERE EXAMPLES OF OTHER NON-FUEL RELATED COSTS THAT THE**
18 **COMMISSION HAS AUTHORIZED FOR RECOVERY IN THE FUEL COST**
19 **RECOVERY RATE?**

20 A Yes. GPC is requesting continued authorization to recover all renewable RFPs and
21 renewable subscription program-related costs that are not otherwise recovered

¹¹ Georgia Power Company, Fuel Cost Recovery Schedule, First Revision, Page No. 10.40. (emphasis added).

1 through bid fees and winner's fees. These are neither fuel nor fuel-related costs. They
2 are not caused by the kWh generated by GPC's power plants or the kWh purchased
3 under GPC's various power purchase agreements. However, GPC rationalizes
4 treating them as fuel costs because the benefits of renewable energy procured through
5 power purchase agreements accrue to customers in the form of lower fuel costs.¹²

6 Similarly, although nuclear PTCs are not fuel costs per se, there is a more
7 direct relationship between tax credits and recoverable fuel costs than the renewable
8 RFP and subscription program-related costs. Unlike renewable RFP costs, nuclear
9 PTCs are caused by the amount of energy generated by eligible nuclear power plants.
10 Like the former, they will directly lower fuel costs. Thus, there is no policy reason not
11 to treat nuclear tax credits as an offset to recoverable fuel expenses.

12 **Q WHAT DO YOU RECOMMEND?**

13 A Consistent with cost causation, the nuclear PTCs should be used to offset the
14 projected FCR-27 costs. These PTCs are not needed to offset storm damage expense
15 to address affordability because applying them to reduce recoverable fuel costs will
16 have the same overall impact. Further, as will be discussed in our testimony in the
17 concurrent storm proceeding, there are more affordable ways to recover storm
18 damage costs than GPC is proposing.

19 **Q DOES THIS CONCLUDE YOUR TESTIMONY?**

20 A Yes.

¹² Direct Testimony of Adam D. Houston and Matthew S. Berrigan at 23.

APPENDIX A

Qualifications of Jeffry Pollock

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A Jeffry Pollock. My business mailing address is 14323 South Outer 40 Rd., Suite 206N,
3 Town and Country, Missouri 63017.

4 **Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

5 A I am an energy advisor and President of J. Pollock, Incorporated.

6 **Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

7 A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree
8 in Business Administration from Washington University. I have also completed a Utility
9 Finance and Accounting course.

10 Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc.
11 (DBA). DBA was incorporated in 1972 assuming the utility rate and economic
12 consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to
13 November 2004, I was a managing principal at Brubaker & Associates (BAI).

14 During my career, I have been engaged in a wide range of consulting
15 assignments including energy and regulatory matters in both the United States and
16 several Canadian provinces. This includes preparing financial and economic studies
17 of investor-owned, cooperative and municipal utilities on revenue requirements, cost
18 of service and rate design, tariff review and analysis, conducting site evaluations,
19 advising clients on electric restructuring issues, assisting clients to procure and
20 manage electricity in both competitive and regulated markets, developing and issuing
21 requests for proposals (RFPs), evaluating RFP responses and contract negotiation
22 and developing and presenting seminars on electricity issues.

1 I have worked on various projects in 31 states and several Canadian provinces,
2 and have testified before the Federal Energy Regulatory Commission, the Ontario
3 Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas,
4 Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky,
5 Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New
6 Mexico, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Utah,
7 Virginia, Washington, Wisconsin and Wyoming. I have also appeared before the City
8 of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City,
9 Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a.
10 Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District
11 Court, and the U.S. Federal District Court.

12 **Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.**

13 A J. Pollock assists clients to procure and manage energy in both regulated and
14 competitive markets. The J. Pollock team also advises clients on energy and
15 regulatory issues. Our clients include commercial, industrial and institutional energy
16 consumers. J. Pollock is a registered broker and Class I aggregator in the State of
17 Texas.

APPENDIX B

1 TO BE INSERTED IN FINAL PDF.

1 BY MR. JONES:

2 Q. Mr. Pollock, did you also cause to be filed
3 with your testimony one exhibit, which is marked
4 Exhibit JP-1?

5 A. Yes.

6 Q. Any changes you need to make to the exhibit?

7 A. No.

8 MR. JONES: Mr. Chairman, I ask that exhibit
9 be marked as GAM 1.

10 CHAIRMAN SHAW: Yep. So marked.

11 (The document referred to was marked for
12 identification as GAM Exhibit 1.)

13 BY MR. JONES:

14 Q. Have you prepared a summary of your testimony
15 today?

16 A. I have.

17 MR. JONES: Mr. Chairman, I ask the witness
18 be given his summary.

19 CHAIRMAN SHAW: Yes, sir. Go ahead,
20 Mr. Pollock.

21 MR. POLLOCK: Good afternoon, Commissioners.
22 My testimony, both in this fuel case, as well as in
23 the pending storm recovery case, emphasizes
24 affordability. That is, how can the Commission set
25 rates to allow Georgia Power Company to recover its

1 going-forward fuel purchase power costs, as well as
2 its deferred and ongoing storm damage costs, while
3 minimizing impacts on customers?

4 Although the company's proposals to
5 concurrently reduce the fuel cost recovery on
6 non-RTP customers or sales, while increasing base
7 rates that affect all customers to recover storm
8 costs, both effective in June 2026, would result in
9 a slight reduction in annual revenues, I think
10 there are more affordable alternatives.

11 As discussed in my FCR-27 testimony before
12 you today, the FCR rates can be reduced further if,
13 one, the Commission were to either pause or review
14 or retain the status quo on Georgia Power Company's
15 natural gas hedging program, which has added
16 274 million to recoverable fuel costs over the
17 36-month period from January 2022 through December
18 2025.

19 Additionally, if -- to the extent that the
20 nuclear production tax credits which were not
21 addressed in the annual rate plan extension that
22 the company is proposing to use to reduce storm
23 damage costs were used to offset recoverable fuel
24 costs, it would result in a more significant
25 reduction in fuel rates that would actually benefit

1 non-RTP sales.

2 First, with respect to hedging, the company
3 has not demonstrated that its natural gas hedging
4 program is providing actual benefits to customers,
5 despite the significant costs incurred. The
6 purpose for hedging should be to meet the market.
7 That is, over the long term you should be able to
8 buy natural gas at a market price while minimizing
9 significant rate spikes and dips. It's not to beat
10 the market.

11 Consistent hedging losses suggest, however,
12 that gas is being purchased at above-market prices.
13 Accordingly, the Commission should reject the
14 company's proposal to expand its hedging program in
15 this case.

16 Second, I think a better hedging strategy
17 would be to use the nuclear production tax credits,
18 of which -- the value of which is \$90 million.
19 That will not only reduce recoverable fuel costs,
20 it will also help to offset the substantial
21 carrying costs that apply to the fuel
22 under-recovery balance.

23 Production tax credits are earned for every
24 kilowatt-hour generated from eligible nuclear
25 production facilities, which includes Georgia Power

1 Company's Hatch and Vogtle Units 1 and 2. Thus,
2 they more closely resemble fuel costs than storm
3 damage costs.

4 Importantly, these tax credits are not
5 related to taxable income, which is a base rate
6 cost. The 90 million is just 25 percent of the
7 value of the tax credits that were generated in
8 2024 and 2025. To the extent that the remaining
9 75 percent of these credits could be used to offset
10 future -- fuel costs in the future, I think that
11 would be a much better hedge.

12 Further, because PTCs are completely
13 unrelated to storm damage, using them to offset
14 storm costs would not be consistent with cost
15 causation because PTCs are directly related to
16 kilowatt-hour supply and not base revenues. Using
17 them to offset recoverable fuel costs, as well as
18 the carrying costs associated with the
19 under-recovered balance, would not only make fuel
20 rates for non-RTP rates more -- sales more
21 affordable, it would also be consistent with cost
22 causation.

23 And, finally, as Commissioner Hubbard
24 observed, paragraph 9 of the fuel cost rate does
25 allow the Commission to include other costs that

1 appropriately reduce recoverable fuel costs, such
2 as production tax credits.

3 As for making storm damage cost recovery more
4 affordable, I'll save that discussion until next
5 week.

6 BY MR. JONES:

7 Q. Does that conclude your summary?

8 A. Yes.

9 MR. JONES: Mr. Chairman, the witness is
10 available for questions from the Commission and
11 other parties.

12 CHAIRMAN SHAW: All right. Commissioners,
13 any questions for Mr. Pollock?

14 COMMISSIONER PRIDEMORE: Thank you for your
15 service, Mr. Pollock.

16 MR. POLLOCK: Thank you.

17 CHAIRMAN SHAW: All right. Moving on.

18 Georgia Interfaith -- well, Georgia Public
19 Service Commission.

20 MR. COLLADO: Thank you, Mr. Chairman. Just
21 a few questions.

22 CROSS-EXAMINATION

23 BY MR. COLLADO:

24 Q. Mr. Pollock, you just recommended using
25 nuclear PTCs to offset fuel costs, rather than storm

1 costs; correct?

2 A. Yes.

3 Q. Okay. Have you quantified the bill impact
4 difference by class under that approach?

5 A. I have not.

6 Q. Okay. Would you agree that the allocation of
7 PTCs in this way would benefit RTP customers more than
8 residential customers?

9 A. They would not apply to RTP customers because
10 RTP sales are not charged the fuel cost recovery rate. So
11 they would benefit non-RTP sales.

12 Q. Okay. So can you explain how it would
13 benefit non-RTP sales again?

14 A. So customers that have -- that are either not
15 on RTP or on RTP that have a CBL are eligible -- or pay
16 the fuel cost rate. So to the extent that you use the
17 nuclear production tax credits to lower the fuel cost
18 rate, it benefits those customers that are not -- it
19 benefits customers other than those that buy on RTP.

20 Q. Would you agree that industrial customers
21 bear almost twice the proportional burden under the fuel
22 revenue allocation as they do under the base revenue
23 allocation?

24 A. The proportionate fuel cost is larger for
25 industrials. I haven't checked if it's device or not.

1 But it also depends upon what we're -- what we're calling
2 industrial customers.

3 Q. Fair enough.

4 Okay. Are there operational -- operational
5 or timing constraints that would prevent the PTCs from
6 being applied to FCR-27?

7 A. I don't think so. Since the company is
8 proposing to utilize them to offset storm damage costs,
9 there's no reason why they couldn't be repurposed.

10 Q. And do you believe that allocating the PTCs
11 through the FCR aligns with the Commission's treatment of
12 other energy-linked credits or incentives?

13 A. I believe so. And, like I said, it's -- PTCs
14 are earned for every kilowatt-hour. They're not a base
15 rate cost. They're not -- they're not related to income
16 or taxes or any other base rate costs.

17 Q. Now, regarding your testimony about hedging,
18 you stated that hedging losses increased fuel costs by
19 \$274 million from 2023 to 2025 in your testimony; is that
20 correct?

21 A. Yes.

22 Q. Okay. Did you evaluate how much hedging
23 contributed to volatility reduction, if at all?

24 A. I did not, no.

25 Q. Okay. And if the Commission terminated

1 hedging, rather than merely rejecting expansion, as staff
2 recommends, would you agree customers would avoid future
3 hedging-related losses?

4 A. Certainly that -- that looks to be the
5 alternative and that -- that would be avoided. But I'm
6 not recommending that the Commission necessarily require
7 the company to completely abandon hedging.

8 And the reason is, if you look at my
9 Exhibit JP-1 and you look at when the gas price spikes
10 mainly occurred -- I mean, they -- they still occur. They
11 mostly occur in the winter months. And it seems to me
12 there should be some role for hedging to be able to
13 mitigate the price spikes that we know tend to occur
14 during the winter period.

15 MR. COLLADO: Thank you. No further
16 questions from staff.

17 CHAIRMAN SHAW: Thank you.

18 Georgia Interfaith Power & Light.

19 MS. WHITFIELD: No questions.

20 CHAIRMAN SHAW: MARTA.

21 MR. BAKER: No questions.

22 CHAIRMAN SHAW: Resource Supply Management.

23 (No response.)

24 CHAIRMAN SHAW: Sierra Club.

25 MS. ARIZA: No questions.

1 CHAIRMAN SHAW: Georgia Power.

2 CROSS-EXAMINATION

3 BY MR. HEWITSON:

4 Q. Mr. Pollock, how are you this afternoon?

5 A. I'm great. How are you?

6 Q. Fantastic.

7 I'm just following up on something. I
8 thought I heard you tell Mr. Collado just right there at
9 the end that PTCs are unrelated to a bunch of things. And
10 I thought one of the things you listed was taxes.

11 A. Right.

12 Q. Right.

13 But you would agree that PTCs are income tax
14 credits; right?

15 A. They are by definition tax credits. That's
16 the "T" and the "C".

17 Q. Okay.

18 A. Yes.

19 Q. Georgia Power can use them to offset income
20 tax on a dollar-for-dollar basis; right?

21 A. To the extent that Georgia Power has taxable
22 income to do so, it can use those to offset income taxes.

23 Q. Okay. And Georgia Power earns a return on
24 its rate base, which is income on which it must pay taxes;
25 right?

1 A. Yes.

2 Q. Georgia Power does not earn a return on its
3 fuel bands; right?

4 A. No. Just the financing costs associated with
5 carrying the over/under collection balance.

6 Q. Okay. So Georgia Power does not generate
7 income on fuel for which it must pay income taxes; is that
8 a fair statement?

9 A. That's right. That's -- it's an expense.

10 MR. HEWITSON: Thank you, Mr. Pollock.

11 That's all I have for you.

12 CHAIRMAN SHAW: Redirect?

13 MR. JONES: No redirect, Mr. Chairman. I
14 just ask that the witness be excused. And that
15 Exhibit JP-1 -- or Exhibit GAM 1 be admitted into
16 the record.

17 (GAM Exhibit 1 was admitted into evidence.)

18 CHAIRMAN SHAW: So marked.

19 Mr. Pollock, you can be excused. Thank you
20 again.

21 MR. POLLOCK: Thank you for your time, as
22 always.

23 CHAIRMAN SHAW: Thank you.

24 All right. Next is Georgia Interfaith
25 Power & Light and Southface. You can call your

1 witness.

2 MR. KAMANI: Good afternoon. Amitav Kamani
3 on behalf of Georgia Interfaith Power & Light and
4 Southface Institute.

5 Mr. Chairman, with your permission, I'd like
6 to call Albert Lin to the stand and swear him in.

7 CHAIRMAN SHAW: Go ahead.

8 MR. KAMANI: Thank you.

9 Mr. Lin, will you please raise your right
10 hand.

11 Thereupon,

12 ALBERT LIN,
13 having been duly sworn, testified as follows:

14 DIRECT EXAMINATION

15 BY MR. KAMANI:

16 Q. Can you please state your full name and full
17 business address for the record.

18 A. Yes. My name is Albert Lin. I conduct
19 business at 26732 Via La Jolla in San Juan Capistrano,
20 California.

21 Q. And by whom are you employed?

22 A. GIPL and Southface.

23 Q. Mr. Lin, on April 9th of this year, did you
24 prepare and cause to be prefiled in this docket 27 pages
25 of direct testimony in question-and-answer format?

1 A. I did.

2 Q. Did you also cause to be prefiled along with
3 your testimony three exhibits marked as Exhibits AL-1, -2,
4 and -3?

5 A. I did.

6 Q. Do you have any changes to your prefiled
7 direct testimony or exhibits at this time?

8 A. I do not.

9 Q. If I were to ask you the same questions that
10 appear in your prefiled testimony at the hearing today
11 under oath, would your answers be the same?

12 A. Yes, they would.

13 MR. KAMANI: Mr. Chairman, I move to have
14 Mr. Lin's direct prefiled testimony be entered into
15 the record as if given orally from the stand.

16 CHAIRMAN SHAW: Yes, sir. So marked.

17 (Whereupon, the prefiled direct testimony
18 of Mr. Lin follows:)

19

20

21

22

23

24

25

April 9, 2026

VIA ELECTRONIC DELIVERY

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334

**Re: Direct Testimony on Behalf of Georgia Interfaith Power & Light and Southface
Institute; Docket No. 56765**

Dear Ms. Tanner:

Please find enclosed an electronic version of the following Direct Testimony **of Albert Lin on
behalf of Georgia Interfaith Power & Light and Southface Institute** to be filed in Docket No.
56765.

Respectfully submitted,



Bob Sherrier
Staff Attorney
Southern Environmental Law Center
Ten 10th Street NW, Suite 1050
Atlanta, Georgia 30309
404-521-9900
bsherrier@selc.org

Counsel for GIPL and Southface

**STATE OF GEORGIA
BEFORE THE
PUBLIC SERVICE COMMISSION**

In Re:	)	
	)	
Georgia Power Company's Fuel Cost	)	Docket No. 56765
Recovery (FCR-27)	)	

**DIRECT TESTIMONY OF ALBERT LIN
ON BEHALF OF
GEORGIA INTERFAITH POWER & LIGHT
AND SOUTHFACE INSTITUTE**

April 9, 2026

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1 **SECTION I. INTRODUCTION AND SUMMARY**

2 **Q: PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

3 A: My name is Albert Lin. I am a consultant with the OG Finance Lab located on the 20000
4 block of Via La Jolla in San Juan Capistrano, California 92675.

5 **Q: PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL**
6 **EXPERIENCE.**

7 A: I have worked in financial analysis and capital markets since 1989. Directly after
8 graduating from the University of Texas at Austin with a Bachelor of Science in Finance,
9 Bachelor of Arts in International Business, and an Honors Business Master's degree, I
10 worked for a regulated utility called General Telephone and Electric ("GTE," now called
11 Verizon). GTE conducted business in over 20 different states in the United States with
12 most of the company's revenue derived from regulated activities approved by Public Utility
13 Commissions ("PUCs") or a similar governmental body in each State GTE conducted
14 business in. My roles were in the finance and audit departments where I analyzed and
15 supported optimal financial outcomes for shareholders within the policies and orders of
16 each respective State's PUC. I focused on the financial and accounting activities that would
17 likely achieve the highest financial returns possible with the least operating risk and
18 variability of outcomes for GTE's equity shareholders. These roles included satisfying
19 credit rating agencies that could impact the cost of debt for GTE, which would likely also
20 affect how shareholders perceived the equity value.

21 After a series of legislative changes culminating in the Telecommunications Act of 1996,
22 the primary activities for GTE were fully de-regulated across the country. Just prior to the

1 passing of the Telecommunications Act of 1996, my work focus shifted to the equity
2 valuation of wireless communications assets, pricing the cost of capital and equity value of
3 wireless communication assets for various Wall Street capital markets firms plus being a
4 founder and partner for a FINRA (Financial Industry Regulatory Authority) registered
5 broker-dealer that focused on equity valuation and forecasts in high-growth industries such
6 as the technology industry sector.

7 Starting in 2012, I served as CEO and Chairperson of the Board of EmberClear
8 Corporation, during which the company developed, permitted, and sold to Ares Capital and
9 ITOCHU Power & Environmental Services three natural gas combined-cycle plants and a
10 zero-emissions integrated gasification combined-cycle with carbon dioxide sequestration
11 and/or re-use plants of 300 to 450 Megawatts of nameplate capacity.

12 From 2020 to the present, I have been focused on economic and financial analysis
13 supporting the energy industry. This includes the regulated utility sector of the United
14 States. More specifically, I have published on matters related to the Return on Equity
15 (ROE) and the Fuel Adjustment Clause (FAC) since 2021. Publications have taken the
16 form of presentation slides, handbooks, whitepapers, and blogs.

17 A copy of my professional resume, which includes my employment history, education, and
18 history of commission and similar hearings, is attached as Exhibit AL-1 to this testimony.

19 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC**
20 **SERVICE COMMISSION?**

21 **A.** Yes. I have testified in general rate cases and fuel rider dockets before this commission.
22 The specific hearings are listed in my CV attached.

1 **Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

2 A: Georgia Interfaith Power and Light (GIPL) and Southface Institute.

3 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

4 A: The purpose of my testimony is to provide the Commission with data and supporting
5 analysis for my recommendations for increased regulatory oversight and transparency of
6 fuel costs. The present trend for the cost of fuel to continue rising with increasing volatility
7 has created a condition where management of the financial exposure and management
8 practices has never been more important since the 1979 “Energy Crisis.” With the cost of
9 fuel accounting for over a quarter of each residential bill, increased attention to rising fuel
10 costs is an urgent matter for affordability and economic prosperity.

11 **Q: WHAT DO YOU HOPE THE COMMISSION WILL TAKE AWAY FROM YOUR**
12 **TESTIMONY?**

13 A: My hope is that my testimony reminds the Commission of the significant risks to customer
14 bills posed by Georgia Power’s deepening reliance on natural gas, and that armed with this
15 knowledge, the Commission will take steps to increase its oversight of fuel costs. In this
16 testimony, I have limited my recommendations to procedural steps to increase oversight in
17 the context of Georgia Power’s recommendations to the contrary. However, the
18 Commission has broad authority to regulate how Georgia Power spends customers’ money.
19 The Commission also has the ability to ensure fair competition between technologies to
20 promote economic efficiency between all technologies available. My recommendations
21 here are merely the first step in that process. I encourage the Commission to think creatively
22 about how to study fuel costs and its impacts on customers; to continue to prioritize
23 diversification of fueled and non-fuel choices; and to carefully consider how the long-held

1 regulatory status quo should be updated to match the changes in the industry to minimize
2 the growing financial risks from increasingly volatile fuel costs.

3 **SECTION II. FINDINGS AND RECOMMENDATIONS**

4 **Q: PLEASE SUMMARIZE YOUR FINDINGS.**

5 **A:** My findings are as follows:

6 1. Natural gas price volatility is hard to manage and places upward pressure on fuel costs.

7 a. Georgia Power Company (GPC or the Company) is investing in more generation
8 using natural gas technologies. Natural gas exhibits more volatile prices than any
9 other major fuel source, and the price volatility of natural gas is increasing. The
10 Company intends to increase future exposure to natural gas generation technologies
11 at a time when many major contributing causes to the price volatility of natural gas
12 continue or have even increased.

13 b. Declines in fuel costs on customer bills in 2026 are the result of paying off the large
14 “financing plan” for the extremely high fuel costs of FCR-26.

15 c. GPC residential customers spend over a quarter (27%) of their total electric bill on
16 fuel costs currently, and as GPC increases exposure to the most price-volatile
17 technologies, customers should expect to see continued pressure from rising fuel
18 costs.

19 2. Financial transparency for fuel costs is lacking.

20 a. Hedging price volatility puts upward pressure on total costs over time. It also
21 obscures the financial risks of GPC’s heavy reliance on natural gas.

- 1 b. Transparency into the Company's fuel cost data and management processes
2 improves efficiency and decreases the risk of future fuel cost price shocks or
3 surprises. The Company's proposed Interim Fuel Rider (IFR) threshold increase to
4 \$300 million and the request for a flexible next filing date for FCR-28 are examples
5 of changes which obscure or delay any party aside from the Company from
6 knowing about the fuel cost amount and volatility over time.
- 7 c. GPC customers do not see fuel cost details on monthly bills by default. The
8 omission of a fuel cost line item for monthly billing lowers visibility into one of the
9 largest portions of a customer's bill.
- 10 d. The Commission's fuel structure—which allows GPC to pass 100% of fuel costs
11 to its customers—erodes GPC's incentive to limit natural gas or use low- and no-
12 fuel energy options.
- 13 e. Additionally, the ability to automatically adjust fuel costs affecting customer bills
14 by 40% above or below the approved rate after the IFR is triggered is extremely
15 high relative to the rate of inflation and further encourages the use of price-volatile
16 fuels.

17 **Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

18 A: Given the findings listed above, the Commission should increase oversight and
19 transparency for fuel cost recovery. Specifically, I recommend that the Commission:

- 20 a. Deny the Company's request to increase the IFR limit, so the Commission and
21 public can better monitor fuel cost changes in a timely manner;
22 b. Set a date for when GPC must propose its next Fuel Cost Rider hearing;

- c. Reduce the maximum amount by which fuel rates can be adjusted during an FCR cycle (i.e., the period between fuel cases) from 40% above or below the approved FCR-27 rates to 15%; and
- d. Order GPC to add a fuel cost line item on monthly bills to all customers.

SECTION III. FUEL COSTS RISING DUE TO NATURAL GAS DEPENDENCY

Q: HOW DOES THE COST OF FUEL IMPACT THE TYPICAL GEORGIA POWER RESIDENTIAL CUSTOMER?

A: For residential customers, the fuel cost over the period of January 2023 - December 2025 averaged 27% of their total bill:

Figure 1: GPC's Historical Period Average Monthly Bill¹

Historical Period (January 2023 - December 2025)

Type of Customer	Historical Period Average Monthly Bill	Percent of Monthly Bill Attributable to Fuel Costs
Municipal-Residential	\$ 160.61	27.11%
County-Residential	\$ 157.67	27.11%
Municipal-Residential, Eligible for Income Qualified Discount	\$ 126.58	27.05%
County-Residential, Eligible for Income Qualified Discount	\$ 124.27	27.05%

Notes:

Bills based on typical residential customer averaging 1,000 kWh per month

"Percent of Monthly Bill Attributable to Fuel Costs" includes FCR charges, Municipal Franchise Fee on FCR charges, and Income Qualified Discount on FCR, if applicable.

Q: YOU CONCLUDE FUEL COSTS ARE RISING. PLEASE EXPLAIN WHAT YOU MEAN.

A: Both Georgia Power's total fuel costs and its customer rate to recover day-to-day fuel costs are increasing. Georgia Power's total fuel expenditures are increasing substantially, due to both the rising cost of fuel and the expected growth in customers' demand for energy.

¹ FCR-27, MFRH-1.1 (PD).

1 Georgia Power's projected customer rate to cover its fuel costs for each unit of energy
2 delivered (Part A of the FCR Rate) is also increasing substantially. The FCR-27 test period
3 shows a 25% increase versus the FCR-26 test period resulting in Part A costs of 3.645-
4 3.6953 cents per kWh.²

5 Q: **WHAT IS CAUSING GEORGIA POWER'S TOTAL FUEL COSTS TO RISE?**

6 A: GPC testifies that its fuel costs for FCR-27's Test Period are \$7.1 billion, a \$1.4 billion
7 (25%) increase over FCR-26.³ Natural gas is the largest portion of fuel costs and energy
8 generation, representing 40.3% of fuel costs and 33.7% of generation.⁴ The Company states
9 that, "compared to the FCR-26 test period, fuel cost for natural gas, including PPAs, is
10 projected to increase by 21% from \$30.91/MWh to \$37.38/MWh."⁵ While the system is
11 growing, the data in the table below shows the Company anticipates fuel costs to rise faster
12 than generation growth and the cost per MWh of electricity. These cost increases come at
13 a time when the Company is planning to use more natural gas than ever before: "On an
14 annual basis, the MMBtu of natural gas burn projected in the test period in FCR-27 is 522
15 million MMBtu compared to the 461 million MMBtu that were projected in the test period
16 in FCR-26 Budget."⁶

² FCR-27, Direct Testimony of Adam H. Houston and Matthew S. Berrigan, page 6 Table 2 and page 15, lines 13–23 (Feb. 17, 2026) ("FCR-27 Houston & Berrigan Testimony").

³ *Id.* at page 15, lines 13–19.

⁴ *Id.* at page 16, Table 3.

⁵ *Id.* at page 16, lines 9–11.

⁶ *Id.* at page 21, lines 14–16.

Figure 2: GPC's Comparison of Projected Fuel Costs⁷

Comparison of Projected Fuel Costs FCR-27 vs FCR-26									
	FCR-27 Test Period (June 2026 - May 2028)			FCR-26 Test Period (June 2023 - May 2025)			FCR-27 vs FCR-26		
	(\$ Millions)	(GWh)	(\$/MWh)	(\$ Millions)	(GWh)	(\$/MWh)	% Change		
Natural Gas*	\$ 2,848	76,187	\$ 37.38	\$ 2,132	65,992	\$ 32.31	34%	15%	16%
Coal	1,258	35,487	35.44	499	9,746	51.15	152%	264%	-31%
Nuclear	427	48,871	8.74	448	46,376	9.66	-5%	5%	-9%
Solar & Hydro	-	4,187	-	-	4,004	-	-	5%	-
Renewable PPAs**	1,218	24,915	48.89	949	18,633	50.93	28%	34%	-4%
Purchases	1,322	36,395	36.34	1,633	39,838	40.98	-19%	-9%	-11%
Total	\$ 7,073	226,041	\$ 31.29	\$ 5,660	184,589	\$ 30.66	25%	22%	2%

*Includes PPA's for which GPC is responsible for purchasing fuel; includes hedge gains/losses

**Includes Solar, Biomass, Wind, and Battery PPA resources

The Company's FCR-27 test period projection in Figure 2 shows just how reliant on natural gas GPC has become. No other fuel cost category is even half as large as natural gas in projected cost, and projected energy generation from natural gas is over 50% greater than the next-highest source of generation (nuclear).

Q: HOW DOES GPC PRESENT ITS FUEL RATE?

A: Georgia Power has a two-part fuel rate, which it then applies to customer bills. "Part A" estimates the rate needed to cover projected fuel costs. "Part B" estimates the rate needed to repay fuel costs that Georgia Power has incurred that it did not anticipate when setting its fuel rates. In other words, "Part A" covers the forecasted day-to-day projected costs of fuel, and "Part B" is a under-recovery mechanism to service the financing plan representing past increases in fuel costs that Georgia Power incurred beyond the projected day-to-day rate.⁸

⁷ MFRP-1, Attachment A PD.

⁸ FCR-27 Houston & Berrigan Testimony, at page 7, lines 1-6.

1 **Q: HAS THE INCREASE IN PROJECTED FUEL COSTS TRANSLATED TO AN**
2 **INCREASE IN THE FUEL RATE CHARGED TO CUSTOMERS?**

3 **A:** Yes. I used the PD versions of Georgia Power’s historic and test-year rate calculators
4 (MFRH-1.1 and MFRP-1.1), the Part A and Part B fuel rates from Georgia Power Exhibit
5 6, and the Line Loss Allocators from Georgia Power Exhibits 5A and 5B to calculate the
6 average monthly fuel cost for the average Georgia Power customer paid in the past versus
7 what he/she will pay in the future, broken out by FCR part.⁹ Georgia Power has proposed
8 increasing Part A of its customer fuel charge by approximately 13% to cover increasing
9 projected costs.

10 **Q: IF THE FUEL COSTS ARE RISING SO RAPIDLY AND THE FUEL RATE IS**
11 **INCREASING, HOW IS IT POSSIBLE THAT GPC EXPECTS CUSTOMER**
12 **BILLS TO DECLINE BY \$5.74/MONTH¹⁰?**

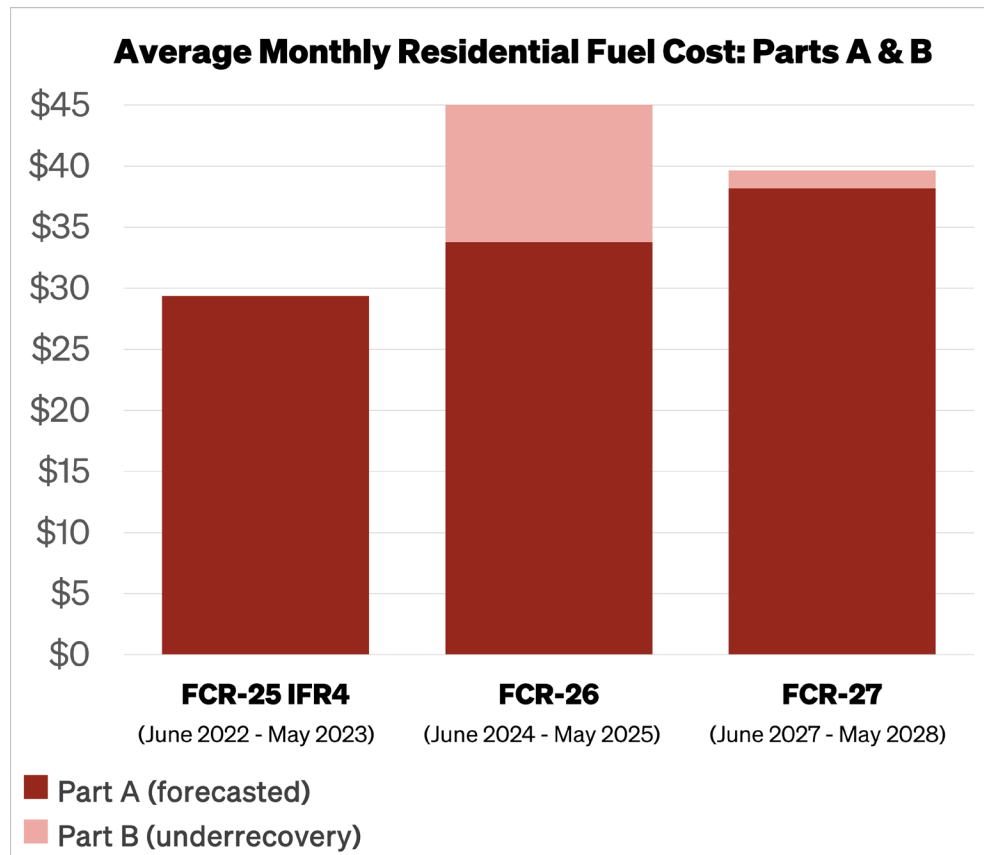
13 **A:** Customers see a smaller bill in 2026 only because they finally finished paying off a three-
14 year “installment plan” from the fuel cost spike of 2022.

15 I used the same analysis described in my previous answer to produce the chart below, which
16 demonstrates how customers’ bills will go down with the adoption of FCR-27 while fuel
17 costs are on the rise. The average Georgia Power customer will pay \$4.38 more per month
18 for current fuel costs than during the FCR-26 period.

⁹ The analysis also accounts for the municipal franchise fee (MFF).

¹⁰ *Id.* at page 6, lines 5–7.

Figure 3: Comparison of FCR-25, FCR-26, and FCR-27¹¹



FCR-27 Part A costs are higher than the FCR-26 Part A costs, which were higher than the FCR-25 costs with the IFR in effect.

Instead, the decrease in overall fuel cost from FCR-26 to FCR-27 is driven by changes in Part B costs. Consider what happened in FCR-26. In that docket, the Commission raised the average customer bill by approximately \$15.94 per month.¹² Over two-thirds of that increase were “Part B” costs designed to pay off a past under-recovery of over \$2 billion,¹³

¹¹ Note that FCR-25 did not split costs into Parts A and B and included no under-recovery of past costs. See FCR-25, Dkt. 43011, Direct Testimony of Sarah P. Adams, page 5 (March 9, 2020).

¹² Georgia Power, 2023 Fuel Cost Recovery, <https://www.georgiapower.com/about/company/filings/fuel-cost.html> (last accessed Apr. 6, 2026) (\$15.94); FCR-26, Dkt. 44902, Rebuttal Testimony of Sarah P. Adams and Adam D. Houston, page 7, line 25 to page 8, line 1 (Apr. 24, 2023) (“approximately \$15.90”).

¹³ FCR-27 Houston & Berrigan Testimony, at page 4, lines 18–20.

1 which was the result of gas prices spiking upward in 2022. (The rest of the increase
2 reflected the rising Part A, forecasted increase in costs of fuel at that time.) Since then,
3 customers have paid over \$10/month to pay off the under-recovery that accrued in 2022.
4 Those billions in under-recovery will finally be paid off on May 31, 2026.¹⁴ So those costs
5 of over \$10/month are removed from the bill.

6 However, as detailed above, the forecasted costs of fuel (Part A) continue to rise, pushing
7 projected day-to-day costs up by over \$4 per month. And even a \$15.94 increase in 2023
8 was not sufficient to cover Georgia Power's fuel costs, so a new (though much smaller)
9 under-recovery has formed (Part B).¹⁵ So in total, though the \$10+ monthly bill for past
10 under-recovery from 2022 will finally expire, bills will only go down by approximately
11 \$5.74/month because the day-to-day cost of fuel continues to rise.

12 Consider the following analogy: Imagine that your air conditioner breaks on a hot August
13 day, forcing you to purchase a replacement using a credit card. Once the credit card balance
14 is finally paid down to zero after 36 months, your monthly household budget breathes a
15 sigh of relief. However, your actual daily living expenses—like groceries, insurance, and
16 property taxes—have actually gotten more expensive in the meantime. Georgia Power is
17 proposing a bill reduction for residential customers of \$5.74 a month, but what really
18 happened is the massive emergency credit card bill from 2023 is finally paid off.¹⁶ So even

¹⁴ *Id.* at page 4, lines 21–23.

¹⁵ *Id.* at page 4, lines 24–26.

¹⁶ Although the decrease in Part B costs is responsible for nearly all of the decrease in customer bills, two additional accounting changes also contribute to reducing customer bills for FCR-27. One results from a legal settlement amounting to \$55.2 million and the other from a change in Georgia's state income tax rate that saved \$13.2 million. *See* FCR-27 Houston & Berrigan Testimony, at page 14, lines 3–14. These two items are indeed savings but are tiny compared to the \$2,200 million of under-recovered fuel costs from FCR-26.

1 though daily living (fuel) expenses are going up, the total monthly charge is going down
2 as a result of the installment plan charges ending. In other words, any messaging about a
3 proposed decrease in customer bills misses the fact that fuel costs are going up.

4 **SECTION IV. NATURAL GAS VOLATILITY**

5 **Q: WHAT IS THE PRIMARY REASON GEORGIA POWER CONTINUES TO**
6 **EXPERIENCE UNDER-RECOVERY OF ITS PROJECTED FUEL COST**
7 **BALANCE, REQUIRING RELIANCE UPON MULTI-YEAR PAYMENT PLANS**
8 **FOR CUSTOMERS?**

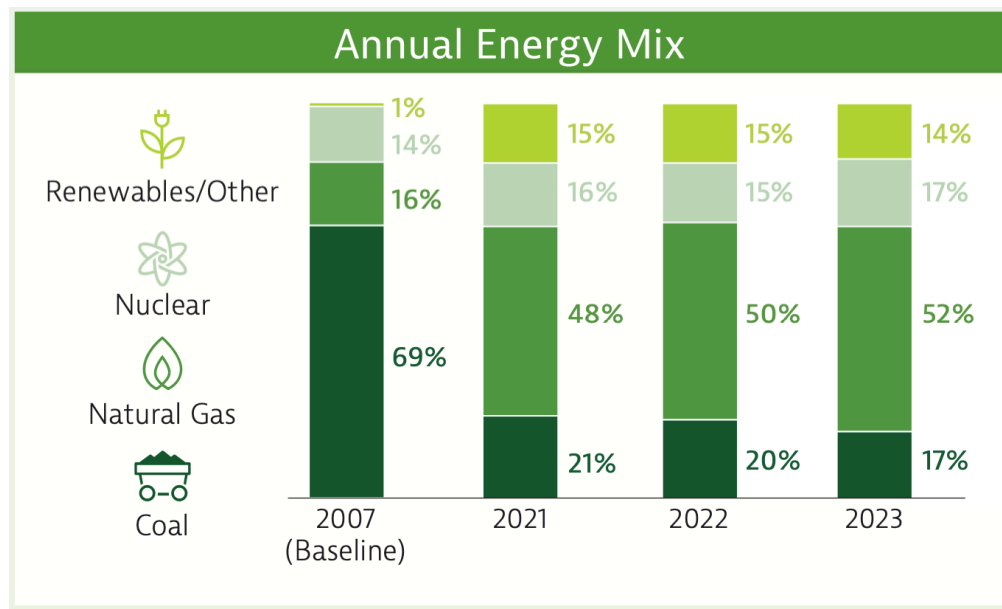
9 A: The primary reason for cost increases is the growing reliance on natural gas as a generation
10 technology. Natural gas prices are very difficult to predict and highly volatile.

11 **Q: TO WHAT EXTENT DOES THE COMPANY RELY ON NATURAL GAS FOR**
12 **POWER GENERATION?**

13 A: As discussed above, natural gas is by far GPC's largest source of power generation. GPC's
14 reliance on natural gas has increased over time.

15 GPC is the largest operating entity of its holding company, Southern Company. Figure 4
16 highlights the company-wide portfolio transition from a 2007 baseline where natural gas
17 was 16% of energy generation to a 2023 energy mix made up of 52% natural gas:

Figure 4: Southern Company Energy Transition¹⁷



I anticipate natural gas fired generation will remain the largest energy source for Georgia Power for many years to come. Company witnesses Houston and Berrigan testified that “[n]atural gas fired generation is projected to be the largest energy source for Georgia Power during the FCR-27 test period, with approximately 40% of the total projected fuel costs coming from natural gas.”¹⁸ Just last year, this Commission approved a nearly-10 gigawatt capacity expansion of the Georgia Power system to be in service by 2031, and approximately 60% of those new resources are fueled by natural gas.¹⁹

Q: WHY ARE NATURAL GAS PRICES SO VOLATILE?

A: Natural gas prices are far more sensitive than other fuels to supply and demand dynamics; any imbalance creates extremely large price changes. This is in part because natural gas

¹⁷ Southern Company, Energy Portfolio Transition & Scenario Planning Presentation (Sept. 2024), <https://www.southerncompany.com/content/dam/southerncompany/sustainability/pdfs/net-zero-transition/energy-portfolio-transition-scenario-planning-fact-sheet.pdf>.

¹⁸ FCR-27 Houston & Berrigan Testimony, at page 19, line 27 to page 20, line 2.

¹⁹ See generally Dkt. Nos. 56298 & 56310; see also Dkt. No. 55378.

has unique physical characteristics, such as the need to use modest-to-high pressure to transport and store the fuel. Moreover, the Company has increased its reliance on natural gas at the same time many other utilities are doing the same.

Figure 5: U.S. Electricity Generation from Natural Gas²⁰

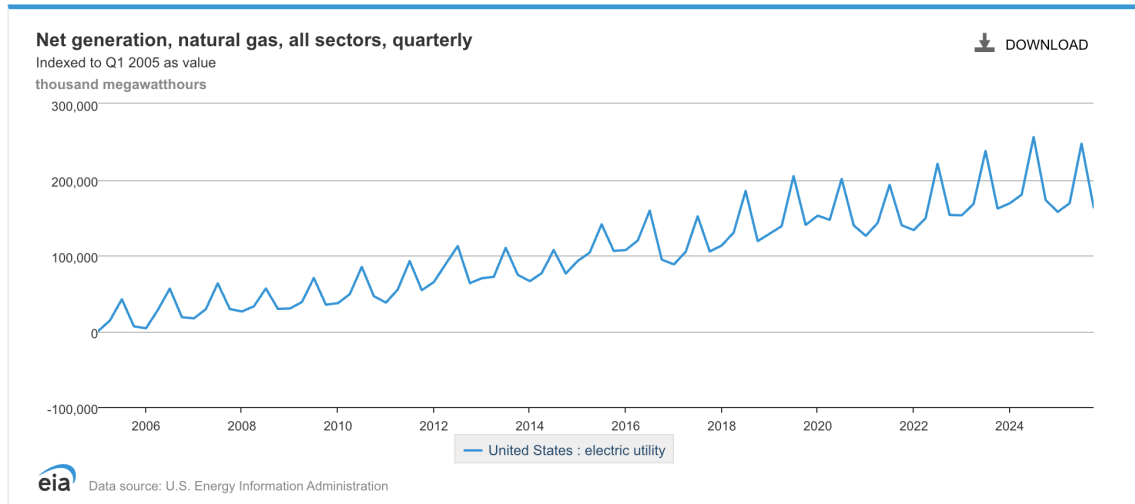
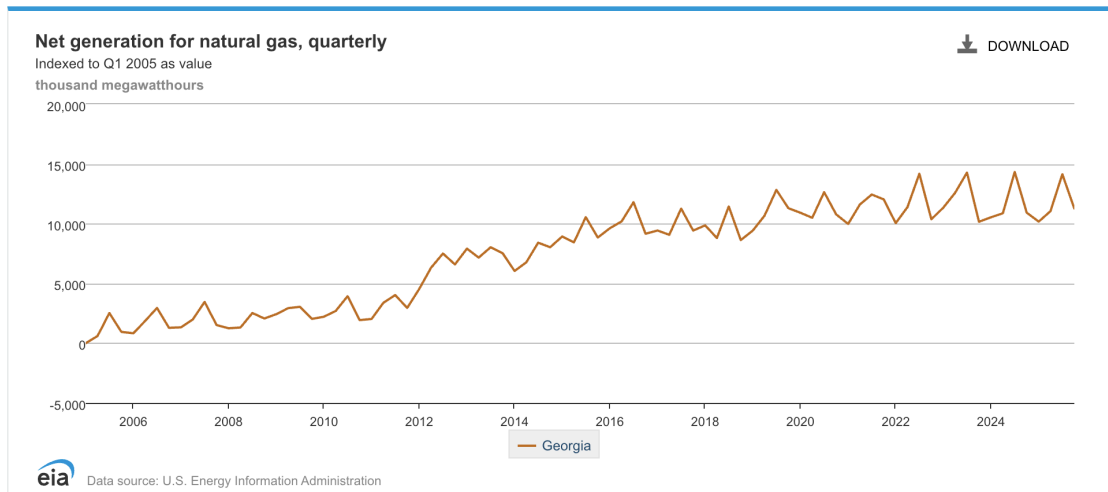


Figure 6: Georgia Electricity Generation from Natural Gas²¹



²⁰ U.S. Energy Info. Admin., Electricity Data Browser, <https://www.eia.gov/electricity/data/> (last accessed Apr. 9, 2026) (filters set for 2005 thru 2025 Nat Gas used for Electricity Generation).

²¹ *Id.* (filters set for 2005 thru 2025 Nat Gas used for Electricity Generation in Georgia).

1 As more utilities concurrently expand their use of natural gas, the common infrastructure
2 required to produce, transport, and store the fuel is placed under increasing demand. This
3 utility-dominated demand reacts to typical utility load cycles, including seasonal spikes
4 during both winter and summer. Such patterns can create periods when supply struggles to
5 keep pace with demand, especially during extreme weather events. When growing demand
6 is combined with lagging transportation and storage infrastructure,²² the result is more
7 frequent instances where the price of natural gas becomes highly volatile and
8 unpredictable. These conditions expose ratepayers to more frequent significant price
9 swings, as supply shortages or bottlenecks lead to sudden and sometimes dramatic
10 increases in cost.

11 Physics and increased U.S. demand for power generation are not the only factors driving
12 natural gas price volatility. The EIA's *Today in Energy* publication listed several factors
13 that contributed to natural gas prices hitting record high volatility in the first quarter of
14 2022.²³ The report stated:

15 U.S. natural gas prices are typically more volatile during the first quarter of
16 a year because of the fluctuating demand for natural gas for space heating
17 as weather changes. Factors that contributed to heightened volatility in the
18 first three months of this year [2022] include:

- 19 • Weather-driven fluctuations in natural gas demand
- 20 • Declining natural gas production in January and February
- 21 • Declines in Lower 48 states' working natural gas levels

²² See Andrew Baker, *East Coast Manufacturers Left in Cold Amid Scarce Natural Gas Pipeline Capacity*, Nat. Gas Intelligence (Feb. 10, 2025), <https://naturalgasintel.com/news/east-coast-manufacturers-left-in-cold-amid-scarce-natural-gas-pipeline-capacity/>; U.S. Energy Info Admin., *Weekly Natural Gas Storage Report for Week Ending in March 27, 2026* (Apr. 2, 2026), <https://ir.eia.gov/secure/ngs/ngs.html> (showing relatively flat trend for gas in underground storage over the past five years).

²³ U.S. Energy Info. Admin., *U.S. natural gas price saw record volatility in the first quarter of 2022* (Aug. 24, 2022), <https://www.eia.gov/todayinenergy/detail.php?id=53579>.

- Record U.S. [liquified natural gas (“LNG”)] exports to Europe to help offset reduced natural gas supplies from Russia

In the years since that 2022 report, geopolitical events have further emerged as a material risk factor for natural gas price spikes. Large governments such as the United States, Germany, and France have also entered the market as competitors to domestic users of natural gas. The recent EU-USA energy purchase agreement announced on July 28, 2025 is designed to have the U.S. Government enter the natural gas market to export \$750 billion of energy to Europe over the next three years, comprised mostly of LNG, petroleum, and nuclear.²⁴ Although I am skeptical that the U.S. will have the physical infrastructure to deliver \$750 billion worth of energy in three years, there is good reason to think that substantial increases in LNG exports to Europe will continue.²⁵ Germany, the largest economy in the EU, has provided state-backed credit to “balance” natural gas supplies whenever necessary at the current market price via an organization called “Trading Hub Europe.”²⁶ France, the second largest economy in the EU, has given citizens a subsidy for energy in the form of “energy checks” after the natural gas price spike in 2022, which enables France to continue obtaining and paying for natural gas even after price spikes.²⁷ These are just two examples of European actions driving demand for LNG. These trends

²⁴ U.S. White House Fact Sheet, *The United States and European Union Reach Massive Trade Deal* (July 28, 2025), <https://www.whitehouse.gov/fact-sheets/2025/07/fact-sheet-the-united-states-and-european-union-reach-massive-trade-deal/>.

²⁵ Nour Eltigani, *US energy stocks surge on \$750 billion EU purchase pledge*, Energy Connects (July 29, 2025), <https://www.energyconnects.com/opinion/features/2025/july/us-energy-stocks-surge-on-750-billion-eu-purchase-pledge/>.

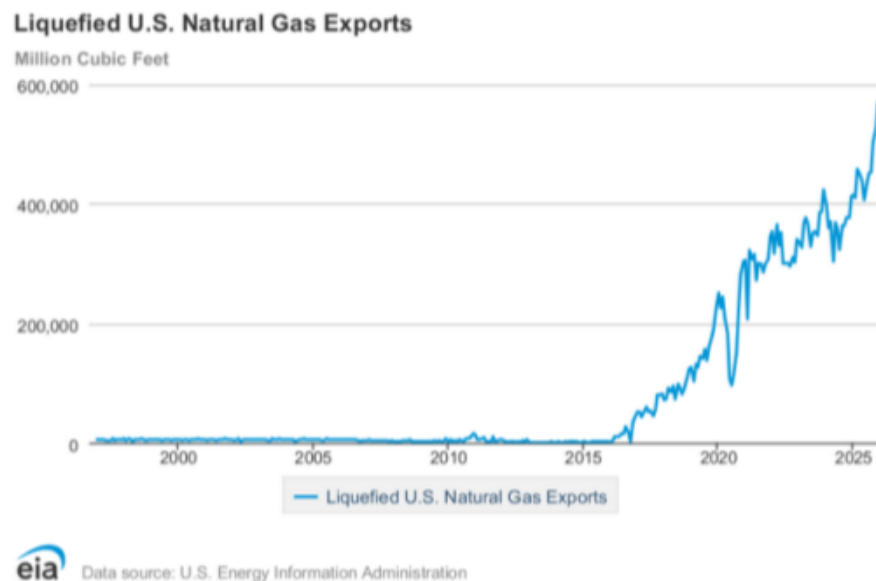
²⁶ Trading Hub Europe, *Information and services for providers of balancing gas and/or services*, <https://www.tradinghub.eu/en-gb/Services/Balancing-gas-supplier/Information> (last accessed Apr. 9, 2026).

²⁷ Service Public, *How to benefit from the energy check in 2026?* (Apr. 1, 2026), <https://www.service-public.gouv.fr/particuliers/actualites/A17885?lang=en>.

1 suggest that the U.S. natural gas industry will shift from domestic investment to LNG sales
2 to Europe and Asia. It is logical to assume that demand from these foreign governments—
3 price-insensitive buyers that are much larger than the entire utility industry—will only
4 stiffen competition for natural gas and place additional upward pressure on gas prices.

5 If extreme price increases in short periods of time occur with greater frequency and
6 if the largest governments in the world agree to buy U.S.-produced natural gas, it
7 is logical to assume that U.S. LNG exporters will take advantage of the high prices
8 and the meteoric rise of LNG exports will continue:

9 **Figure 7: Natural Gas Export Volumes from the United States²⁸**



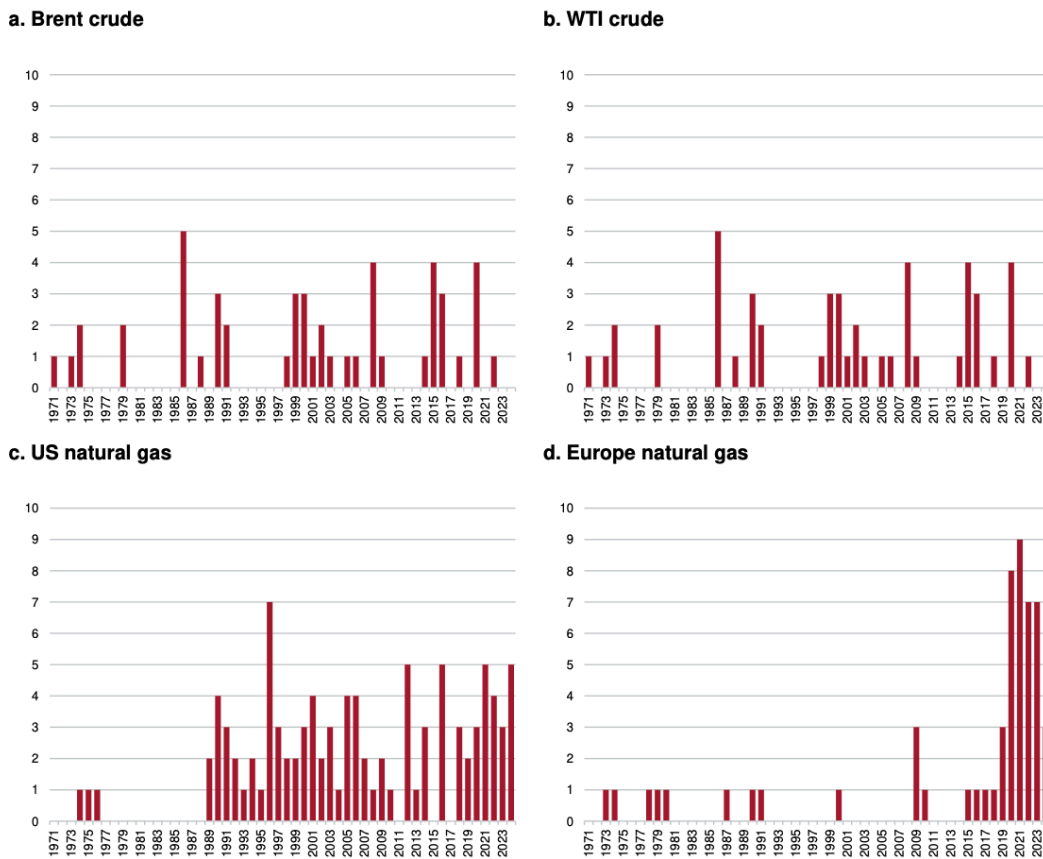
10
11 **Q: JUST HOW VOLATILE ARE NATURAL GAS PRICES?**

²⁸ U.S. Energy Info. Admin., Liquefied Natural Gas Exports (March 31, 2026),
<https://www.eia.gov/dnav/ng/hist/n9133us2m.htm>

A: Natural gas price volatility has overtaken the price volatility of crude oil, which used to be the benchmark for a high volatility large commodity. This trend has become more pronounced in recent years. A recent study from the Elcano Royal Institute analyzed historical trading data and measured the number of months where price variations for natural gas exceeded 15 percent, an indicator of volatility.²⁹ The report illustrated the findings as “Figure 3” which I have reproduced here in Lin Figure 8.

Figure 8: Natural Gas Price Volatility Surpasses Oil Price Volatility

Figure 3. Monthly price variations greater than 15% (number of months per year)



Source: the authors based on World Bank data.

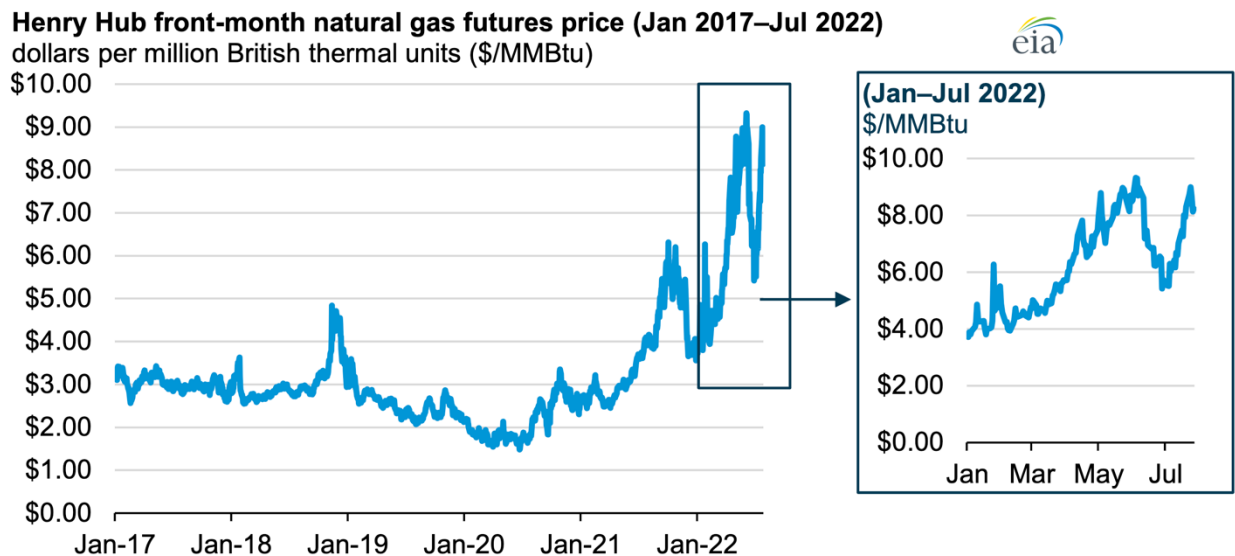
²⁹ Enrique Feás & Isidoro Tapia, *The Volatility of Energy Prices and its Effect on Industry*, Elcano Royal Inst. (Mar. 20, 2025), <https://www.realinstitutoelcano.org/en/analyses/the-volatility-of-energy-prices-and-its-effect-on-industry/>.

The findings show that price volatility for natural gas in the United States has far exceeded price volatility of crude oil for the past 35 years. The graphic also reflects the fact that volatility may compound for many months or longer.

In addition to the Elcano study, studies from the U.S. Department of Energy examining historical prices point to a growing trend in natural gas price volatility in the United States.

In 2022, the U.S. Energy Information Administration (“EIA”) published a chart depicting the volatility of natural gas prices, which is presented here as Figure 9.

Figure 9: Natural Gas Price Volatility Trend 2017–2022³⁰

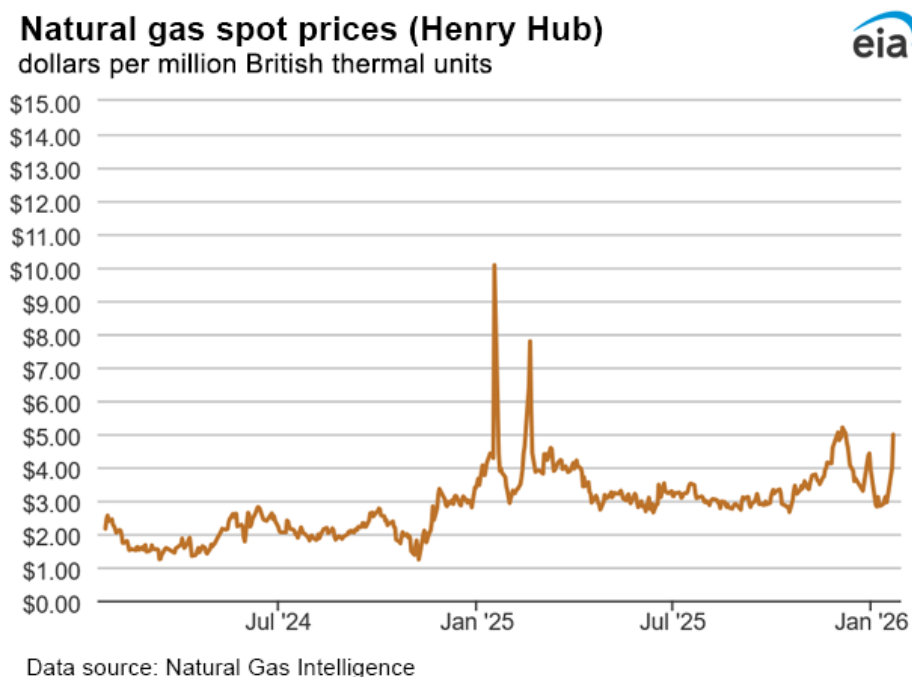


Data source: CME Group, Bloomberg, L.P.

As Figure 9 illustrates, natural gas prices were highly volatile in the 2017–2022 period, with all-time price volatility records set in 2022. That extremely high volatility has continued, as seen in the EIA’s January 2026 publication reproduced here as Figure 10.

³⁰ U.S. Energy Info. Admin., *U.S. natural gas price saw record volatility in the first quarter of 2022* (Aug. 24, 2022), <https://www.eia.gov/todayinenergy/detail.php?id=53579>.

Figure 10: Natural Gas Price Volatility Trend 2023–2026³¹



Q: HAS NATURAL GAS PRICE VOLATILITY BEEN A LONG-STANDING ISSUE?

A: Yes. However, the electricity industry’s exposure to natural gas and its price volatility is a recent phenomenon which was not a material concern when natural gas generation was largely used for peaking load demand. In 2004, the Massachusetts Institute of Technology (“MIT”) conducted one of the earliest studies to quantify the volatility of natural gas prices in the United States.³² Although the MIT study was published over 20 years ago, it used historical trading data to demonstrate that natural gas price volatility was greater than crude

³¹ U.S. Energy Info. Admin., Natural Gas Weekly Update (Jan. 22, 2026), https://www.eia.gov/naturalgas/weekly/?utm_medium=email.

³² Robert S. Pyndick, *Volatility in Natural Gas and Oil Markets*, JOURNAL OF ENERGY & DEV. Vol. 30 No.1 (2004), https://web.mit.edu/rpindyck/www/Papers/Vol_NG.pdf.

1 oil price volatility even prior to 2004.³³ For much of the last 70 years, crude oil was seen
2 as the larger and more important fuel compared to natural gas. Crude oil prices were
3 considered extremely hard to predict despite the size of the market and financial motivation
4 to make accurate predictions.³⁴ Today, the same can be said about natural gas.

5 **Q: IF NATURAL GAS EXPOSURE IS VERY LARGE AND PRICES ARE VERY**
6 **VOLATILE, CAN THE PRICE BE PREDICTED TO AVOID LARGE CHANGES**
7 **IN THE LEVELIZED COST OF FUEL?**

8 A: No. Natural gas prices cannot be reliably predicted—and not for lack of effort. Given the
9 large amount of money involved in the energy commodities industry, there is enormous
10 financial motivation to accurately predict future prices.³⁵ Company Witnesses Houston and
11 Berrigan agree with the experts; they testify that, “Taken together, these factors suggest a
12 tighter supply-demand balance and the potential for continued natural gas price
13 volatility.”³⁶

14 **Q: HAS THE COMPANY EXPERIENCED HIGH NATURAL GAS PRICE**
15 **VOLATILITY?**

16 A: Yes. As the Company observes, “Natural gas prices remain subject to significant volatility.
17 . . . [T]his volatility can be seen in the wide range of spot prices at Henry Hub, which

³³ *Id.* at 7–8.

³⁴ See generally James D. Hamilton, *Understanding Crude Oil Prices*, NAT’L BUREAU OF ECON. RSCH. (Nov. 2008), https://www.nber.org/system/files/working_papers/w14492/w14492.pdf.

³⁵ See Bagher Modjtahedi & Nahid Movassagh, *Natural-gas futures: Bias, predictive performance, and the theory of storage*, 27 ELSEVIER ENERGY ECON. 617 (2005) <https://www.sciencedirect.com/science/article/abs/pii/S0140988305000538>; see also Mark Bolinger et al., *Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation*, ERNEST ORLANDO LAWRENCE BERKELEY NAT’L LAB’Y (2003), <https://eta-publications.lbl.gov/sites/default/files/report-lbnl-53587.pdf>.

³⁶ FCR-27 Houston & Berrigan Testimony, at page 15, lines 8–10.

1 ranged from \$1.23 to \$12.97 per MMBtu in 2023 through 2025.”³⁷ Wide-ranging
2 fluctuations have continued this year: the Company testified that “as recently as late
3 January 2026, Henry Hub natural gas prices rose above \$30 per MMBtu during Winter
4 Storm Fern, illustrating the ongoing potential for volatility in natural gas markets.”³⁸ I urge
5 the Commission to consider the significant cost risks that accompany Georgia Power’s
6 deepening reliance on natural gas, which has fluctuated in price tenfold in just the past
7 three years.

8 **SECTION V. SHORTCOMINGS OF THE COMPANY’S PROPOSALS**

9 **Q: DO YOU AGREE WITH GPC THAT ADDITIONAL HEDGING OF THE**
10 **NATURAL GAS FUEL COST WOULD HELP MITIGATE THE INCREASING**
11 **PRICE PRESSURES FROM NATURAL GAS?**

12 **A:** Not necessarily. Georgia Power testifies that hedging is critical. Specifically, the Company
13 states: “For a Company like Georgia Power that anticipates consuming more than 250
14 million MMBtu of natural gas per year, a robust hedging program serves as a critical tool
15 to mitigate upward price volatility for customers.”³⁹ The Company describes the following
16 benefits of hedging:

- 17 1. Mitigate upward price volatility of natural gas.⁴⁰
- 18 2. Fix and cap costs for a portion of the natural gas purchased.⁴¹

³⁷ *Id.* at page 20, lines 9–11.

³⁸ *Id.* at page 21, lines 1–3.

³⁹ *Id.* at page 20, lines 13–15.

⁴⁰ *Id.* at page 19, lines 26–27.

⁴¹ *Id.* at page 20, lines 3–6.

1 3. Provide rate stability for customers.⁴²

2 But although hedging blunts the impacts of extreme price spikes for natural gas, overall, it
3 can also put upward pressure on natural gas prices for customers.

4 Hedging behaves just like insurance. The utility is the buyer of the insurance. If the
5 Company wants to have a known maximum price for the natural gas it purchases, the price
6 volatility risk must be taken by a counterparty who agrees to absorb the risk for a cost—
7 essentially, an insurance premium. These counterparties understand the risk and know the
8 price volatility of natural gas as well as Georgia Power does. They will accordingly charge
9 a rate for the insurance that allows them to profit over time. So, increased hedging may
10 keep costs for customers steadier in the long run, but it will keep them steadily high.

11 **Q: HAS THE COMPANY IDENTIFIED THE AMOUNT OF HEDGING OPTIMAL**
12 **FOR ITS CUSTOMERS?**

13 A: I cannot answer that question based on this record. Under the current regulatory framework,
14 the Company can pass through 100% of hedging costs to (most) customers. In a
15 competitive marketplace, a rational actor would only buy as much hedging as needed to
16 offset the risk that a catastrophic event would impair its financial security. But because
17 Georgia Power bears none of the hedging costs, it has minimal incentive to evaluate the
18 optimal amount of hedging for its customers.

19 For the same reason, GPC has limited incentive to investigate whether the problems it seeks
20 to solve through increased hedging are in fact symptoms of overreliance on a highly
21 volatile resource. Rather than continuing to hedge a higher and higher percentage of its

⁴² *Id.* at page 4, lines 13–15.

1 natural gas purchases and thus lock in a higher and higher floor for fuel costs, the Company
2 might—if it had incentive to—reconsider its fuel mix or the expected costs for hedging
3 over time.

4 I recognize that Georgia has a long-standing practice of passing 100% of fuel costs to
5 customers. As such, Georgia will likely see greater risks for fuel cost increases unless the
6 practices are updated in a manner where the incentives align with the risks. In the
7 meantime, I urge the Commission to approach Georgia Power’s assessment of financial
8 benefits concerning fuel cost management with the knowledge that the financial risks are
9 rising and being borne by the customer.

10 **Q: IF HEDGING CANNOT SOLVE FOR VOLATILE AND RISING NATURAL GAS**
11 **COSTS, COULD A HIGHER IFR THRESHOLD BE USEFUL?**

12 A: No. The IFR is the threshold that triggers both the Company’s reporting requirements to
13 the Commission and the public and its ability to adjust its fuel rate. The Company
14 “proposes to increase the IFR threshold from the current amount of \$200 million approved
15 by the Commission to \$300 million.”⁴³

16 The IFR is a tool to help the Commission respond to fuel cost volatility. To be sure, the
17 current level of natural gas price volatility appears to have surpassed what Georgia Power
18 predicted when fuel rates and the IFR levels were set. And because Georgia Power is
19 deepening its reliance on natural gas, the most volatile and hard to predict fuel, the odds of
20 the current IFR threshold being exceeded are indeed rising.

⁴³ *Id.* at page 22, lines 5–6.

1 But higher-than-expected price volatility is not sufficient reason to allow an increase in the
2 IFR threshold. Raising the IFR threshold from \$200 million to \$300 million essentially
3 hides significant cost increases from public view for a longer period. That undermines a
4 primary benefit of the IFR: for the Commission and the public to obtain information about
5 unexpected fuel costs accruing on customers' balance before it becomes a much larger
6 surprise. Further, the IFR notification period alerts the Commission and customers of fuel
7 volatility and to the fact that Georgia Power is carrying an unexpected fuel balance, which
8 is compounded by carrying costs, which are also passed to customers. This information
9 allows the Commission to consider corrective action.

10 I recommend keeping the current level even if the \$200 million level results in more
11 frequent reporting of the data.

12 **Q: DO YOU HAVE ANY ADDITIONAL OBSERVATIONS ABOUT THE IFR?**

13 A: Yes. If the IFR is triggered, GPC may adjust customer fuel rates by a certain percentage
14 above the rate approved in the fuel cost proceeding. Before FCR-26, GPC could adjust
15 rates by up to 15% above the approved rate if the IFR were triggered.⁴⁴ In the FCR-26
16 order, the Commission updated that percentage to 40%.⁴⁵ 40% is extremely high relative
17 to the rate of inflation and further encourages the use of price volatile fuels. I recommend
18 that percentage should be lowered back to 15%.

19 **Q: THE COMPANY IS NOT PROPOSING A SPECIFIC DATE FOR ITS NEXT**
20 **FUEL CASE. DO YOU AGREE WITH THIS APPROACH?**

⁴⁴ FCR-26, Direct Testimony of Sarah P. Adams and Adam D. Houston, page 21, lines 18–19 (Feb. 28, 2023).

⁴⁵ FCR-26, Order Adopting Stipulation, Dkt. No. 44902, at 4 (May 25, 2023).

1 A: No. Given GPC's rising fuel costs and increased exposure to the most price-volatile of
2 fuels, the fuel cases are more important than ever. The Company highlights this growing
3 issue and risk when it states that its "recommended change to the IFR mechanism will also
4 enable the Company and the Commission to respond in a more timely and effective manner
5 to fuel price volatility, thereby further mitigating the need to establish a fixed date for the
6 next fuel case at this time."⁴⁶ The Commission should question the logic and prudence of
7 how increasing the IFR threshold and thereby lowering the frequency of the fuel case—the
8 one regularly occurring docket that provides oversight and transparency for the over \$3
9 billion dollars of annual fuel costs—better addresses the rising risks identified by the
10 Company than simply scheduling another fuel case. I recommend the Commission ask the
11 Company to set a fuel case date just as it has done in the past.

12 **Q: HAVE YOU IDENTIFIED ANY OTHER OPPORTUNITIES TO INCREASE**
13 **TRANSPARENCY IN CUSTOMERS' FUEL COSTS?**

14 A: Yes. All parties, including consumers, should understand fuel costs represent a very large
15 portion of the total bill. As such, the fuel cost is a stand-alone item worthy of disclosure.
16 Customer bills do not currently display this information, so most customers are likely
17 unaware of the size of fuel costs and the extent of fuel price volatility over time. I therefore
18 recommend that the Commission order GPC to provide a fuel cost line item on all customer
19 bills.

20 **SECTION VI. CONCLUSIONS**

21 **Q: WHAT ARE YOUR RECOMMENDATIONS FOR THE COMMISSION?**

⁴⁶ FCR-27 Houston & Berrigan Testimony, at page 25, lines 15–18.

1 A: I recommend that the Commission:

- 2 - Deny the Company's request to increase the IFR limit, so the Commission and public
3 can better monitor fuel cost changes in a timely manner;
4 - Set a date for when GPC must propose its next Fuel Cost Rider hearing;
5 - Reduce the maximum amount by which fuel rates can be adjusted during an FCR cycle
6 (i.e., the period between fuel cases) from 40% above or below the approved FCR-27
7 rates to 15%; and
8 - Order GPC to add a fuel cost line item on monthly bills to all customers.

9 **Q: ARE THERE OTHER RESOURCES OR PERSPECTIVES WHICH MAY BE**
10 **HELPFUL FOR THE COMMISSION?**

11 A: Yes. There has been information and testimony given to the Commission in the prior FCR-
12 26 hearing which may add to the understanding of the issues being addressed in FCR-27.
13 Witnesses Jeremy Kalin and Brent Alderfer both address relevant fuel cost topics
14 applicable to the current FCR-27:

- 15 • The misaligned interest of having 100% of the fuel cost paid by a party which does
16 not possess the information or ability to impact the cost.
17 • The structural and persistent price volatility of natural gas should be expected.
18 • Other states have started to address fuel cost price shocks and annual increases
19 beyond forecasts.

20 Their testimonies are attached as Exhibits AL-2 and AL-3, respectively.

21 **Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

22 A: Yes, it does.

STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	Docket No. 56765
Fuel Cost Recovery (FCR-27)	)	

EXHIBIT AL-1

ALBERT LIN

SKILLS

- **Financial Consulting on ROE and Regulatory Policy**
- **Equity Investment and Valuation (Broker-Dealer Operations)**
- **Energy Generation Development (IGCC/CCGT)**
- **Board of Directors (Governance) of publicly traded and private companies**

EXPERIENCE HIGHLIGHTS

Consultant | Gizmo Global | 2015-Present

Financial Consulting focused on the energy industry with emphasis on the electricity system of the USA. Acted in capacity of executive, manager, and consultant to The Finance Lab as well as other electricity dense users such as data centers

Energy Policy Analysis | OG Finance Lab | 2020-Present

Directing the OG Finance Lab to assist energy policy stakeholders on financial incentives and implications.

Providing key features of legislation governing fuel clause adjustment (CO Bill 2022/2023) and analyzing the impact of ROE rate setting for regulated utilities in the United States

CEO and Chairperson of the Board | EmberClear | 2008-2015

Electricity Generation Asset Developer. Permitted, developed, sold IGCC and CCGT power plants to PE Funds and Large International Power Plant Operators ranging in sizes from 330 – 450 Megawatts

SUMMARY

Finance executive and entrepreneur in capital markets focused on consulting to the energy industry in recent years. Providing perspective and analysis of impacts of energy policy when new technology and practices are present constitute most consulting engagements.



alin@soonercap.com



(415) 409-9150



<https://www.linkedin.com/in/linalbert/>

Managing Director | AmTech | 2002-2007

Co-Founder for a Technology Focused broker dealer.
Acted as Director of Research for 24 equity analysts. Sold
to a publicly traded competitor after annual revenue
per employee exceeded \$1MM in 2007

Equities Analyst | Various | 1992-2002

Sell-side equities analyst in wireless communications for
SG Cowen & Co, Soundview Financial, and Rauscher
Pierce.

Buy-side technology portfolio manager for

The Abernathy Group, Meerkat Capital, and Ivory
Capital. Managed portfolio of high growth technology
equities in a long-short strategy.

Finance Manager | Verizon | 1989-1992

Various finance and audit positions at regulated
telecommunications company General Telephone &
Electric which became Verizon Communications.
Prepared financial analysis used for regulatory and
shareholder meetings

**EDUCATION
& OTHER****University of Texas @ Austin (1989)**

BS: Finance

BA: International Business

Honors Masters Business Degree

**Guest Lecturer at Boston College
Graduate School of Business 2020-
2023 "Blockchain & Crypto
Currencies"**

**FINRA Series 7,24,63,65 (licenses
granted, but no longer sponsored)**

Electricity Industry Details

Regulatory Engagements:

Public Service Commission of South Carolina Duke Energy Carolinas, LLC
General Rate Case Docket 2025-172-E (December 2025)

Public Service Commission of South Carolina Duke Energy Progress, LLC General
Rate Case Docket 2025-154-E (November 2025)

North Carolina Utilities Commission Duke Energy Progress, LLC Fuel and Fuel-
Related Charge Adjustments Docket E-7 Sub 1358 (November 2025)

Virginia State Corporation Commission Virginia Electric & Power Company Fuel
Factor Hearing PUR 2025-00059 (July 2025)

North Carolina Utilities Commission Duke Energy Carolinas, LLC Fuel and Fuel-
Related Charge Adjustments Docket E-7 Sub 1313 (June 2025)

Montana Public Services Commission educational ROE discussions and analysis
of Northwestern Energy General Rate Case (2024.05.053) and Montana-Dakota
Utilities General Rate Case (2024.04.061) with Northern Plains Resource Council
(Jan 2025)

PacifiCorp Rocky Mountain Power General Rate Case ROE expert witness in
Utah for Western Resource Advocates (Dec 2024)

ROE workshop for RE-AMP serving Midwest USA (Aug 2024)

Dominion Energy South Carolina General Rate Case (24-035-04) ROE expert
witness in South Carolina (June 2024)

Electricity Industry Details

Regulatory Engagements (Continued):

Georgia Power Yates Certification Hearing (No. 55378) expert witness in Georgia for Sierra Club and Southern Alliance for Clean Energy (May 2024)

Testified and attended drafting sessions for Colorado SB291 to legislate fuel cost sharing for Colorado Public Utilities Commission (April 2023)

Natural gas price risk discussion with South Carolina Legislators (12 total) for Southern Alliance for Clean Energy (Feb 2023)

Ex-Parte discussion of natural gas price risk to Public Services Commission and Office of Regulatory Staff in South Carolina (Jan 2023)

STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	Docket No. 56765
Fuel Cost Recovery (FCR-27)	)	

EXHIBIT AL-2

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re: Georgia Power Company's	)	
2023 Fuel Cost Recovery (FCR)	)	Docket No. 44902
Application	)	

DIRECT TESTIMONY

OF

JEREMY KALIN

ON BEHALF OF SIERRA CLUB AND SOUTHERN ALLIANCE FOR CLEAN ENERGY

("SACE")

14 April 2023

1 **Q: PLEASE STATE YOUR NAME, POSITION, AND ADDRESS.**

2 **A:** My name is Jeremy Kalin. My business address is c/o Avisen Legal, P.A., 901 Marquette
3 Avenue South, Suite 1675, Minneapolis MN 55402.

4 **Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

5 **A:** Sierra Club and Southern Alliance for Clean Energy (“SACE”).

6 **Q: PLEASE DISCUSS YOUR RELEVANT EXPERIENCE, PROFESSIONAL EXPERTISE,**
7 **AND EDUCATIONAL BACKGROUND.**

8 **A:** I am an advisor, consultant, attorney and shareholder at Avisen Legal, P.A. in Minneapolis,
9 Minnesota. I am licensed to practice law in the State of Minnesota and the District of Columbia, first
10 admitted to the Minnesota Bar in 2010. I serve as legal counsel to energy developers, investors, advocates,
11 project hosts and state and local governments across the United States in my areas of expertise. I also serve
12 as consultant and advisor in a number of capacities and organizations, including the Pearl Street Station
13 Finance Lab; to the non-partisan nonprofit energy thought leadership organization RMI, the bipartisan
14 National Caucus of Environmental Legislators, and the Novogradac Renewable Energy Tax Credit
15 Working Group. I have attached a copy of my CV to my testimony (JK-Exhibit 1). I am an author of the
16 recent paper published by Pearl Street Station Finance Lab, “Learning To Share: A Primer On Fuel-Cost
17 Pass-Through Reform” which I have provided as an Exhibit to this testimony (JK-Exhibit 2).

18 I was elected to the Minnesota House of Representatives for two terms, where I served on the
19 Energy Policy and Finance Committee, authoring numerous energy bills that became law including the
20 Demand Efficiency Act, the Next Generation Energy Act, the Public Building Enhanced Energy Efficiency
21 Program and the Commercial Property Assessed Clean Energy Act. Building on my research while a law
22 student, I also authored the 2010 Ratepayer Protection Act calling for Commission action to better align
23 utility financial incentives with macroeconomic factors and public policy goals at the state and federal level;
24 while that bill did not become law, it was one of earlier calls across the country to modernize electric utility
25 incentive structures, including the calls to update the Fuel Cost Recovery mechanism in Georgia and in
26 dozens of other states.

1 From 2010 to 2017, I was CEO of Eutectics Consulting LLC, a mission-driven company focused
2 on financing energy projects in underserved and untapped markets. Among other projects, in 2013, I led
3 my company's work updating the nationally-recognized Energy Assurance Plan for the State of Minnesota.
4 While in public office, I served as state legislative liaison for the White House climate and clean energy
5 policy team, and later advised the U.S. Department of Energy Jobs Strategy Council under Democratic and
6 Republican Secretaries.

7 My undergraduate degree is from the University of Minnesota. I pursued graduate studies in the
8 University of New Mexico School of Architecture and Planning for two years and have a Juris Doctorate
9 from William Mitchell College of Law in St. Paul, Minnesota. Like so many lawyers and former elected
10 officials, my undergraduate degree is a Bachelor of Fine Arts in ceramics, and I spent several years as a
11 working potter and teacher.

12 **Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA COMMISSION?**

13 **A:** No. This is my first time testifying before the Georgia Public Service Commission.

14 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

15 **A:** In my testimony, I provide the following:

- 16 1. An overview of the relevant history of fuel-cost pass-through policies in place across
17 the United States, including Georgia's Fuel Cost Recovery mechanism, to provide
18 context for Georgia Power's FCR-25 and FCR-26 rate increases;
- 19 2. A specific discussion of the "moral hazard" presented by Georgia's Fuel Cost
20 Recovery mechanism, and why the Georgia Power request poses a significant threat to
21 Georgia ratepayers' economic wellbeing;
- 22 3. Factors the Commission should consider in evaluating whether Georgia Power's
23 significant rate increases are prudent and justifiable, given Georgia Power's implied
24 admission that the utility has not taken any meaningful steps to reduce ratepayers'
25 exposure to Georgia Power's fuel costs;

- 1 4. The potential negative impact on reliability of continuing the current Fuel Cost
2 Recovery mechanism, including an overreliance on natural gas as an electric
3 generation source, wherein 100% of fuel costs are passed through to ratepayers, as
4 proposed by Georgia Power in this docket;
- 5 5. A brief discussion of Georgia Power's proposal to essentially eliminate the need for
6 future Fuel Cost Recovery dockets by increasing the Interim Fuel Rider cap to 40%.
- 7 6. A brief response to the proposed April 12, 2023 Stipulation between Georgia Power
8 and the Georgia Public Service Commission Public Interest Advocacy Staff.
- 9 7. A recommendation to the Commission to establish a specific docket to more deeply
10 evaluate the benefits of requiring some amount of risk and cost-sharing by Georgia
11 Power in managing its fuel supply, including the benefits to ratepayers; to overall
12 system reliability; to emissions and to national security. A modernized Fuel Cost
13 Recovery mechanism could allow Georgia Power to secure earnings for its
14 shareholders, while better protecting its customers from fuel price spikes and fuel price
15 volatility.

16 **Q: WHAT DOCUMENTS DID YOU REVIEW IN PREPARING THIS TESTIMONY?**

17 **A:** I have reviewed Georgia Power's Direct Testimony; other Georgia Power filings as part of the
18 docket; many of the Minimum Filing Requirement documents, and Georgia's Fuel Cost Recovery statute,
19 O.C.G.A. 46-2-26. I have briefly reviewed other relevant sections of O.C.G.A. 46-2-20 through 46-2-33,
20 as well as Department 515 Rules of Georgia, Public Service Commission. Further, I have reviewed the
21 April 12, 2023 Stipulation between Georgia Power and Georgia Public Service Commission Public Interest
22 Advocacy Staff as a proposed resolution to the Company's request in this docket, as well as the proposed
23 revised Interim Fuel Rider provision attached to the Stipulation as Attachment A.

24 I have also briefly reviewed previous Fuel Cost Recovery dockets and other Commission materials
25 to which I refer in this testimony. All of the material I reviewed is public data; I did not receive any trade
26 secret or otherwise confidential information.

1 **Q: PLEASE SUMMARIZE YOUR TESTIMONY**

2 **A:** In my testimony I provide the following:

- 3 • In the matter of the FCR-25 tariff under-recovered fuel balance, the Commission should rigorously
4 review the prudence of Georgia Power's actions. While Georgia Power could not have predicted
5 the specific events that contributed to the under-recovered fuel balance, multiple experts warned of
6 the risks of excessive reliance on natural gas and the ongoing price volatility of natural gas even
7 without winter storm Uri and Russia's invasion of Ukraine. Georgia Power could have taken any
8 number of prudent steps to minimize its exposure to natural gas price volatility.
- 9 • The Commission should not approve the forward-looking FCR-26 fuel rate adjustment. The
10 Commission should instead initiate a Fuel Cost Recovery modernization docket to include some
11 amount of fuel-cost-sharing and fuel-risk-sharing by the utility, to mitigate the moral hazard under
12 the current policy of passing through 100% of fuel costs to ratepayers. The Commission has the
13 authority under the Fuel Cost Recovery statute -- because of Georgia Power's failure to take
14 sufficient prudent steps -- to make amendments that would better allocate risk and costs between
15 utilities and ratepayers. A modernization docket is the best means to evaluate all the policy options,
16 relevant factors and potential impacts.
- 17 • Georgia Power's proposal to increase the Interim Fuel Rider maximum adjustment to 40% without
18 Commission review risks violating the Commission's statutory responsibility to conduct a
19 prudence review of Georgia Power's fuel costs. The Commission should reject this proposal.
- 20 • Georgia Power's proposals also risk the utility's strong prior record on reliability. Addressing Fuel
21 Cost Recovery tariffs without considering the impact of other ratemaking dockets has led to
22 unintended consequences, including an outsized reliance on natural gas. Other non-fuel
23 alternatives could have mitigated the multi-billion-dollar impact to ratepayers.

24
25 **I. HISTORY OF FUEL COST RECOVERY POLICIES**

1 **Q: WHAT IS THE HISTORY OF FUEL PASS THROUGH CLAUSES, INCLUDING**
2 **GEORGIA'S FUEL COST RECOVERY MECHANISM?**

3 **A:** During most of the first 100 years of the electric power industry, fuel costs were the complete
4 responsibility of utilities.

5 The Chicago Gas Trust was incorporated in 1887 with an authorized \$25,000,000 in capital shares,
6 and soon acquired controlling interests in the four gas companies operating in Chicago for just \$300,000.
7 Immediately after the merger, gas prices rose 25%, which the Chicago Tribune blasted as “gas extortion.”
8 While it took 20 more years for states to adopt the first Public Utility Commissions, the outcry over the
9 Chicago Gas Trust consolidation helped cement the public’s interest in affordable, stable and reliable utility
10 service, overseen by a utility commission.¹

11 Ultimately, the National Electric Light Association (NELA) argued in 1907 for what we know
12 today as the electric utility regulatory compact. Sustainable business models for electric utilities in 1907
13 depended on access to capital to expand utility service and accepting state regulation with public oversight
14 of capital investments would provide stable access to capital. NELA’s Subcommittee on Public Regulation
15 and Control wrote, “[I]t should be impressed upon the officials controlling public-utility corporations that
16 the public will is that these companies shall exist, not primarily to make dividends upon certain investments
17 of capital, but as the most efficient means of supplying the public’s needs.”²In the interest of consumer
18 protection and incentivizing efficient production of electricity, the newly created public utility commissions
19 included fuel costs as just one of the utility’s many costs of doing business. These “inputs” were not a
20 unique cost category requiring special ratemaking treatment.

¹ Harold Platt, *The Electric City: Energy and the Growth of the Chicago Area, 1880-1930* (University of Chicago Press 1991) provides a good history of the early days of market development, competition, consolidation and predatory behavior that led to the National Electric Light Association’s call for regulation in exchange for a guaranteed utility service territory, the foundation of the electrical regulatory compact we know today, including in Georgia.

² National Electric Light Association, *Proceedings* 1907, p 649.

1 When World War I disrupted oil, coal, and gas supply globally and in the United States, causing
2 fuel prices to soar, utilities lobbied commissions for relief from fuel-price volatility and the associated risk
3 of significant financial loss. Public utility commissions responded by implementing the first temporary fuel-
4 pass-through policies, and then discontinued the practice shortly after World War I's end.

5 World War II again disrupted global oil, coal and gas supply across the world, and again public
6 utility commissions responded. The fuel pass-through-policy protected utilities from the severe supply
7 challenges and price volatility. With domestic purchasing constrained by rationing and a national call for
8 energy conservation, increased electricity bills – including the new fuel pass through costs - were likely
9 understood as a citizen's contribution to the war effort. When peacetime returned to the United States,
10 commissions again reverted to the prior policy, and for nearly 30 years, utilities were responsible for 100%
11 of the fuel costs for power generation.³

12 The oil shocks of the 1970s sparked new utility demands to be insulated from global geopolitics
13 and supply constraints. This time, state legislators joined utility commissions in adopting fuel pass through
14 policies, ultimately enacting statutes such as Georgia's Fuel Cost Recovery Statute, O.C.G.A. 46-2-26,
15 adopted by the Georgia Legislature in 1979.

16 The gasoline lines have disappeared, and the United States is substantially more energy secure than
17 it was during the first days of OPEC. But while the wide lapels and bad disco dancing of the 1970s have
18 been relegated to the history pages, the 100% pass-through-policies of fuel costs are still the law of the land
19 in Georgia and nearly all other states.⁴

³ Electric Consumers Resource Council, "Fuel Adjustment Clauses and other Cost Trackers," <https://elcon.org/fuel-adjustment-clauses-cost-trackers/>, accessed April 10, 2023.

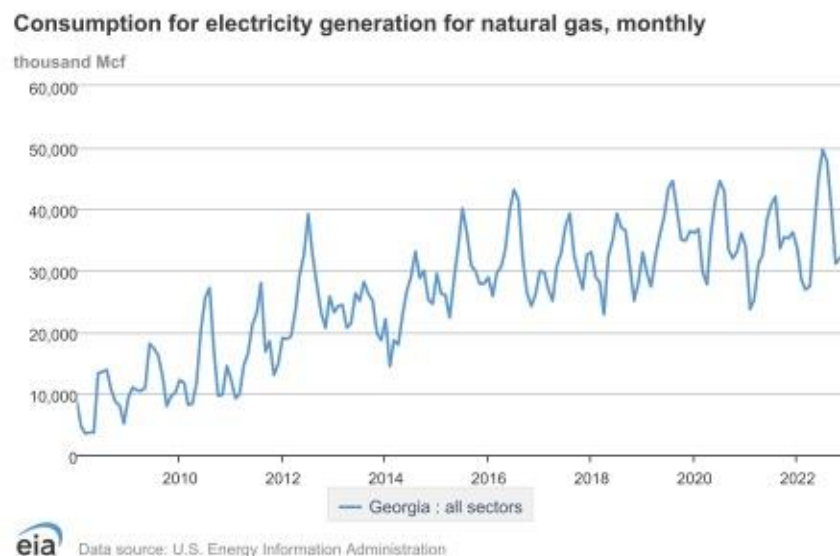
⁴ S&P Global Market Intelligence, *RRA Regulatory Focus: Adjustment Clauses, a state by state overview 2* (2017), <https://www.spglobal.com/marketintelligence/en/documents/adjustment-clauses-state-by-state-overview.pdf>.

Q: HOW IS THIS HISTORY RELEVANT TO THIS DOCKET AND GEORGIA POWER'S REQUEST TO RECOVER UNDER-COLLECTED COSTS UNDER FCR-25 RATES AND TO INCREASE RATES IN THE FCR-26 TARIFF GOING FORWARD?

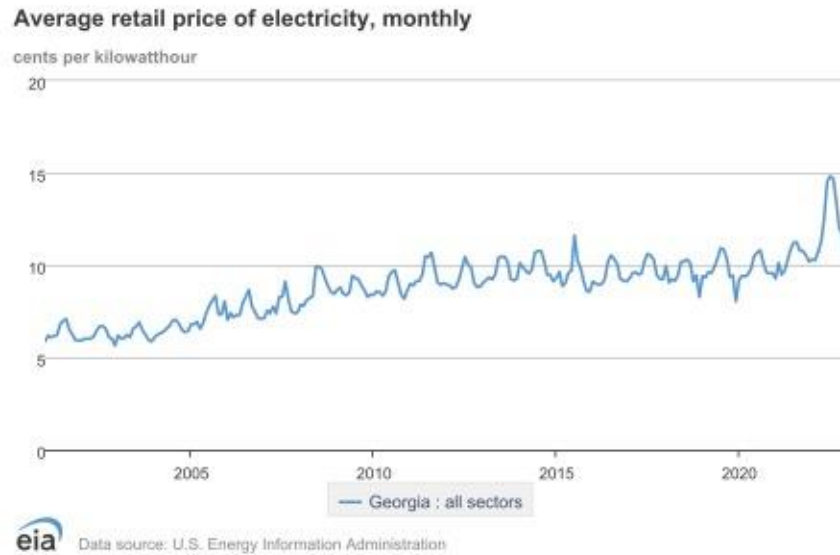
A: While the Fuel Cost Recovery has been in statute for 44 years, it is important to remember that utilities have been responsible for managing fuel costs and fuel price risks for most of the 116 years of utility regulation in the United States. The Fuel Cost Recovery pass-through policy is not a required element of the regulatory compact but is instead a regulatory creation.

The following two charts show the correlation between: (1) increased consumption of natural gas for power generation in Georgia, as shown in Chart 1, from 2008 to 2023, and (2) increased per-kilowatt-hour (per-kWh) retail rates for all ratepayers in Georgia, as shown in Chart 2, from 2000 to 2023.

Chart 1



1

Chart 2

2

3 During this period, utilities have borne 0% of responsibility for fuel costs and managing fuel risk in
 4 Georgia and have passed 100% of both fuel costs and fuel risks to ratepayers.

5 **II. FUEL COST RECOVERY'S MORAL HAZARD**

6 **Q: WHAT IS A “MORAL HAZARD?”**

7 **A:** In general terms, a moral hazard occurs when one party is incentivized to take more risk than they
 8 normally would because that party is insulated against that risk.⁵ In other words, a moral hazard exists when
 9 the consequences of a decision are so disconnected from the decisionmaker that that party takes a bigger
 10 risk as a result.

11 **Q: HOW IS THE MORAL HAZARD EMBODIED IN GEORGIA'S FUEL COST RECOVERY**
 12 **STATUTE, O.C.G.A. 46-2-26?**

13 **A:** Georgia's Fuel Cost Recovery statute permits Commission-regulated utilities to charge its
 14 ratepayers a rate sufficient to recover the cost of fuel, through a proposed formula based on “an estimate of

⁵ See generally Mark Thoma, *Explainer: What is Moral Hazard*, CBS News (Nov. 22, 2013), <https://www.cbsnews.com/news/explainer-moral-hazard/>.

1 [the utility's] fuel costs and retail sales for the next three conservative months and proposed base rates to
2 recover those costs" (paragraph c) and an amendment which "shall include an adjustment based on actual
3 expense to date in order that the accumulated retail costs of the utility shall equal, as nearly as possible, the
4 revenues recovered pursuant to the fuel recovery allowance..." (paragraph g).

5 While the statute does not require the utility to collect all of its fuel costs from ratepayers, O.C.G.A.
6 46-2-26 does permit the utility to set fuel recovery rates that pass along 100% of the fuel costs to ratepayers.⁶
7 Georgia's fuel pass through policy is consistent with the pass-through statutes and Commission rules in
8 nearly every other state. Like so often happens in policymaking, the 1970's energy crisis merited a response
9 of some sort to address the global volatility at the time, not just in thermoelectric generation fuel
10 procurement but across the oil, gas and coal industries. The trade-offs of the 1970s and early 1980s –
11 exchanging consumer exposure to fuel costs in exchange for complete insulation of utility risk – may have
12 made sense then. Though I understand some consumer advocates cited the potential moral hazard at the
13 time, the 44-year history of the Georgia's Fuel Cost Recovery – and this current request from Georgia
14 Power – shine a harsh light on the perils of continuing this policy of 100% pass-through to ratepayers, and
15 0% responsibility for the costs and risks by shareholders.

16 **Q: DO YOU READ THE STATUTE TO REQUIRE THE COMMISSION TO IMPLEMENT**
17 **FUEL COST RECOVERY IN A MANNER THAT EXACERBATES THE MORAL HAZARD?**

18 **A:** No, I do not.

19 I have seen enough similar fuel-cost pass-through statutes to support my belief that O.C.G.A. 46-
20 2-26 provides enough flexibility for the Commission to adjust the risk- and cost-sharing ratios of the Fuel
21 Cost Recovery mechanism in Georgia.

22 In O.C.G.A. 46-2-26(c), the statute requires the utility to propose "base rate tariffs to recover those
23 (fuel) costs." The statute does not require the utility to propose a rate tariff to recover all of its fuel costs. I
24 have read several sections of related Georgia statute and Commission rules, and have not yet seen any

⁶ Georgia Public Service Commission background on Fuel Cost Recovery, undated, http://www.psc.state.ga.us/electric/regulation/Fuel_Cost_Recovery.pdf, accessed April 10, 2023.

1 requirement that the Commission must approve a utility's fuel rate tariff such that the utility recovers 100%
2 of its fuel costs – only that the Commission may approve such a tariff.

3 I see several areas where the Commission may establish a fuel rate tariff requiring the utility to
4 accept some amount of responsibility for fuel costs and fuel risks. In particular, 46-2-26(e) requires the
5 Commission to “issue an order stating the base rates to be used by the utility” going forward. This language
6 suggests that the Commission has wide latitude, consistent with other sections of the Georgia Code and
7 under Commission rules and policies, to modify the proposed fuel tariff, as the Commission has done
8 specifically in prior Fuel Cost Recovery (FCR) dockets. For instance, in docket 19142-U, decided May 17,
9 2005, the Commission reduced the FCR tariff proposed by Georgia Power, recognizing excess costs due to
10 replacement energy expenses during unscheduled outages, and in docket 11884-U, decided March 30, 2000,
11 the Commission made multiple changes to the proposed FCR tariff, in consideration of other pending rate-
12 related matters by the filing utility, Savannah Electric and Power Company. In multiple Fuel Cost Recovery
13 tariff dockets, the Commission has reduced the proposed FCR tariff by requiring extended amortization
14 periods, including in dockets 19142-U and 21229-U, presumably during periods of lesser natural gas price
15 volatility than these past three years.

16 **Q: DID YOU REVIEW THE DIRECT TESTIMONY OF MS. SARAH ADAMS AND MR.**
17 **HOUSTON ON BEHALF OF GEORGIA POWER?**

18 **A:** Yes.

19 **Q: WHERE IN THE UTILITY'S TESTIMONY AND MINIMUM FILING REQUIREMENT**
20 **DOCUMENTS DO YOU SEE THIS MORAL HAZARD IMPACTING GEORGIA POWER**
21 **RATEPAYERS?**

22 **A:** Georgia Power's own supporting documents show a 78.4% increase from the current FCR-25 IFR-
23 4 rates to the proposed FCR-26 rates, and an 87.4% summer rate increase.⁷

⁷ MFRP-1C.

1 I am hard pressed to find any better example of how ratepayers are bearing the cost of this moral
2 hazard. It is not an academic question for many families, particularly those living on tight budgets. As a
3 business owner, I also know the stress that such severe rate increases have on businesses doing everything
4 they can to control costs and remain competitive in a global business environment.

5 **Q: HOW WOULD YOU DESCRIBE THE SCALE OF GEORGIA POWER'S FUEL COST**
6 **RECOVERY RATE INCREASE PROPOSALS?**

7 **A:** Georgia Power's proposed rate increase is shocking, and the numbers speak for themselves.

8 I also believe that the Company may be muddying the waters as to the full scope of the Fuel Cost
9 Recovery impact on ratepayers. Georgia Power has proposed amortizing the under-recovered fuel balance
10 over 36 months rather than 24 months. It is unclear, if the FCR would be higher -- a 117.6% increase rather
11 than the stated 78.4% increase -- if the shorter amortization period were applied. If so, "shocking" would
12 no longer properly capture the scale of this rate increase.

13 In addition to the massive impact on individuals with limited means, the utility's proposed Fuel
14 Cost Recovery rate increase has implications for broader regional competitiveness. Georgia businesses are
15 no different from others across the country, facing significant challenges in attracting and retaining qualified
16 employees. While the state of Georgia certainly has much to offer in terms of quality of life, the cost of
17 living is a significant factor when workers decide where to make their home, and where to ply their trades
18 -- including the cost of rent and home ownership, as well as the cost of energy during hot Georgia summers.

19 I understand that Georgia Power's per-kilowatt rates are just below the national average, overall.
20 However, when it comes to overall electric bills, Georgia ratepayers pay the 8th highest average monthly
21 electric bills in the country. Only South Carolinians pay a higher average monthly electric bill in the region.⁸
22 Georgia Power's Fuel Cost Recovery rate increase request is substantially higher than the impact of Duke
23 Energy Carolina's pending fuel cost pass through rate increase request in South Carolina, by approximately

⁸ EIA 2021 Average Monthly Bill -- Residential.

1 \$1.24 to \$7.24 per month more.⁹ Depending on the final amortization period selected, Georgia Power's
2 Fuel Cost Recovery rate request would likely make Georgians' electric bills the highest in the Southeast.

3
4 **III. FACTORS FOR "PRUDENT" REVIEW BY THE COMMISSION**

5 **Q: COMPARING GEORGIA POWER'S REQUEST WITH OTHER FUEL COST**
6 **RECOVERY REQUESTS NATIONALLY, DO YOU SEE SOME POSITIVES?**

7 **A:** Yes, very much so.

8 First, the best measurement of the efficiency of fuel costs to electric output is the ratio of fuel dollars
9 spent for each Megawatt hour (MWh). Consistent with the stated challenges of the Company's request,
10 Georgia Power states that the dollar per megawatt hour (\$/MWh) fuel cost for coal, natural gas and nuclear
11 generation resources, and the costs of purchased power, are projected to increase 97%, 92%, 17% and 28%
12 respectively. While I believe the utility could have prudently mitigated these increases through procurement
13 of non-fuel technologies such as solar and energy storage, I am very pleased to see the utility use the \$/MWh
14 metric for measuring economic efficiency.¹⁰

15 Second, Georgia Power recognizes that generation from renewable resources lowers the utility's
16 overall cost of fuel.¹¹ It may be self-evident, but worth stating explicitly, that the use of non-fuel generation
17 technologies adds MWhs to the utility's generation mix without any fuel costs that need to be first paid by
18 the utility and then passed along to ratepayers. With the Inflation Reduction Act's increased tax credits for
19 many non-fuel generation options, including solar, energy storage, wind and clean hydrogen, among others,
20 these non-fuel resources will continue to be even more cost-competitive and even cost-advantageous to the
21 utility's ratepayers. While ratemaking should never be conducted in a vacuum or from a single-issue
22 perspective, the advantages of \$0 fuel costs for such resources warrant diversifying the utility's generation
23 mix.

⁹ Docket 2022-3-E, South Carolina.

¹⁰ Direct Testimony of Ms. Adams and Mr. Houston on behalf of Georgia Power Company, Docket No. 44902, p. 15.

¹¹ Ibid.

1 Third, Georgia Power recognizes that the Commission has substantial flexibility under the Fuel
2 Cost Recovery statute, O.C.G.A. 46-2-26, to modify the specific mechanisms of Fuel Cost Recovery and
3 the specific amounts that the utility can collect. I disagree with Georgia Power's proposal to authorize the
4 utility to effectively remove the need for Fuel Cost Recovery dockets. But I do agree with Georgia Power
5 that the Commission has sufficient latitude and authority to protect ratepayers by reforming the Fuel Cost
6 Recovery itself.

7 **Q: ARE THERE ELEMENTS OF GEORGIA POWER'S REQUEST THAT REQUIRE**
8 **FURTHER CLARIFICATION?**

9 **A:** Yes.

10 The Company's Direct Testimony includes in its list of other "primary drivers" to the increased
11 fuel costs "energy purchased from a variety of renewable resources such as solar, wind, and biomass."¹²
12 While biomass may have input costs, solar and wind generation technologies do not include fuel costs.

13 Further, the Company states that the FCR-26 upward rate adjustment will increase a typical
14 residential customer's bills approximately \$17 to \$23. I believe that this \$204 to \$276 annual cost to a
15 typical Georgia Power residential customer is understated by a factor of 50%, as the utility has proposed
16 extending the recovery period out from the conventional two years to a total of three years. The Commission
17 would be wise to secure utility clarification on this cost impact where the under-recovered balance from
18 FCR-25 rates amortized over just the two years.

19 **Q: IS THE COMMISSION REQUIRED TO ACCEPT GEORGIA POWER'S POSITION**
20 **THAT THE UTILITY COLLECT ALL OF ITS FUEL COSTS?**

21 **A:** No. Georgia's Fuel Cost Recovery statute states that the utility bears the burden of proof to show
22 that the costs are prudent, as previously discussed. Ken Costello stated it best when he described these
23 utility cost recovery claims:

¹² Direct Testimony, p. 17.

1 Utilities sometimes convey the false assertion that they have a right to recover any costs they
2 incurred, even before the regulator has assessed their reasonableness. Their position seems to be
3 that “we expend money to satisfy mandates or serve our customers, so regulators should allow us
4 recovery of this money in rates with little scrutiny.” It presumes that regulators should trust that
5 utilities will always act in the public interest. Good regulation would question the prudence and
6 legitimacy of any costs; it owes that much to utility customers.¹³

7 **Q: IN REVIEWING GEORGIA POWER’S FUEL COST RECOVERY RATE REQUEST,**
8 **WHAT STANDARD SHOULD THE COMMISSION APPLY?**

9 **A:** The Fuel Cost Recovery statute states that the Commission shall “make appropriate adjustment for
10 any reported fuel cost that is the result of illegal or **clearly imprudent conduct** on the part of the utility”
11 (emphasis added).

12 **Q: DID YOU SEE EVIDENCE THAT GEORGIA POWER HAS TAKEN PRUDENT STEPS**
13 **TO REDUCE THE UTILITY’S FUEL COSTS DURING THE FCR-25 RATE PERIOD?**

14 **A:** I do not see much evidence that the Company has taken sufficient prudent steps to protect ratepayers
15 during the prior FCR-25 rate period.

16 **Q: PLEASE EXPLAIN.**

17 **A:** Sometimes, common sense can be as useful as precedent. Merriam-Webster defines the term
18 “imprudent” as “lacking discretion, wisdom, or good judgment.” Collins defines the term as “without
19 thought of consequences; lacking in judgment or caution; rash; indiscreet.”

20 As recently as last year, Georgia Power was warned that a continued reliance on highly volatile
21 natural gas pricing, combined with the elevated coal market pricing and high volatility, would lead to this
22 exact scenario of excessive fuel costs.¹⁴ In the midst of the worst effects of the Russian invasion of Ukraine
23 and global concerns about inflation dominating the news every day, Georgia Power submitted and

¹³ Ken Costello, “Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives,” National Regulatory Research Institute, April 2014, p. 23.

¹⁴ Post-hearing brief of Southern Alliance for Clean Energy (SACE) and Southface Energy Institute (Southface), dockets 44160 and 44161, July 7, 2022, pp. 17-18.

1 advocated for the Company's triennial Integrated Resource Plan (IRP) and a Stipulation between the
2 Company and the PSC Public Interest Advocacy Staff to procure Power Purchase Agreements from six
3 natural gas plants.

4 On October 12, 2021, the Company had already recognized the substantial under-recovered fuel
5 balance in the wake of winter storm Uri's natural gas price spikes in Georgia and nationally and filed the
6 Interim Fuel Rider Notification and Plan with the Commission, increasing the FCR-25 Fuel Cost Recovery
7 rates by the maximum 15%. As the Company testified in this current docket, "despite implementing the
8 maximum allowed 15% increase... (which took effect in January 2022), the Company's [] under-recovered
9 fuel balance increased dramatically in 2022."¹⁵

10 Yet, even as the Company was monitoring this "dramatic" increase in natural gas costs, Georgia
11 Power persisted with their pursuit of even more costly and risky natural gas resources in the IRP and DSM
12 Stipulation of 2022. Intervenors Southern Alliance for Clean Energy and Southface Energy Institute
13 specifically recommended that Georgia Power not proceed with such plans, and that the Commission
14 consider an order "setting an upper limit on the recovery of fuel costs for (the) PPAs to adequately protect
15 ratepayers from market volatility and unprecedented price spikes."¹⁶ In his Direct Testimony in these IRP
16 and DSM Stipulation 2022 dockets, witness Ron Binz, former Chair of the Colorado Public Utility
17 Commission, repeatedly highlighted the risks associated with natural gas spikes.¹⁷

18 **Q: DID YOU SEE ANY EVIDENCE THAT GEORGIA POWER PLANS TO TAKE**
19 **SUFFICIENT PRUDENT STEPS TO REDUCE THE UTILITY'S FUEL COSTS GOING**
20 **FORWARD, AS PROPOSED BY THE INCREASED FCR-26 RATE?**

21 **A:** No, at least not enough evidence that the Company is prudently trying to reduce its fuel costs
22 looking forward.

23 **Q: PLEASE EXPLAIN.**

¹⁵ Direct Testimony, p. 13

¹⁶ Post-hearing brief of SACE and Southface, dockets 44160 and 44161, p. 18.

¹⁷ Ibid.

1 **A:** In discussing steps the Company is taking to mitigate the impact of FCR-26 rates on its customers,
2 Ms. Adams and Mr. Houston point to only one Company action to reduce the actual fuel costs for Georgia
3 Power operations;¹⁸ this additional procurement of fuel-free solar generation resources amounts to only
4 0.006%¹⁹ of the total GWH's projected total power generation according to the Company's own filings in
5 their Direct Testimony.²⁰

6 When specifically describing the Company's efforts to mitigate the impact of fuel costs on
7 ratepayers, Georgia Power boasts of implementing the maximum Interim Fuel Rider (IFR) increase on
8 ratepayers of approximately 15% effective January 1, 2022.²¹ Implementing an IFR increase is not actually
9 a cost mitigation method, but instead is a risk mitigation method for the utility, at the literal expense of
10 ratepayers. Rather than reducing actual fuel costs paid by the Company to generate electricity at coal- and
11 natural-gas-fired power plants, increasing the IFR merely passes along the utility's increased fuel costs to
12 its customers. The utility is thus allowed to collect more via the higher FCR tariff, effectively providing a
13 further disincentive to the utility to aggressively reduce the fuel costs themselves. The IFR mechanism
14 worsens the moral hazard, rather than mitigates it.

15 Further, the utility cites as a positive cost-mitigation method its proposed amortization of the \$2.6
16 billion under-recovered fuel balance under FCR-25 over 36 months instead of the more conventional 24
17 months. Again, this is not actually a fuel cost mitigation measure. Instead, Georgia Power is effectively
18 double-charging customers by increasing the forward-looking FCR-26 rates starting June 1, 2023, and
19 adding on top of it the 36 months of amortized costs for prior fuel costs. This proposal is akin to a family
20 charging its monthly grocery bills on the credit card, and spending the next three months paying off that
21 month's grocery bills. That same family will need to buy groceries each subsequent month, but will be

¹⁸ Direct Testimony, p. 9 and p. 15.

¹⁹ 1,150 GWh of the total 184,589 GWh projected on Table 2 of the Direct Testimony of Ms. Adams and Mr. Houston, p. 16.

²⁰ Ibid, p. 16.

²¹ Ibid, p. 14.

1 paying principal and interest on the prior three month's groceries, making it harder and harder to make the
2 family budget balance.

3 In Georgia Power's case, they are proposing a similar painful negative-feedback-loop of increased
4 costs, with very minimal stated efforts to reduce actual fuel costs. And the impact on a typical residential
5 customer in Georgia is profound. Over each of the three years of FCR-25 under-recovered collections, that
6 typical residential customer will pay between \$204 and \$276 more on their Georgia Power bills.²² If the
7 Commission instead uses the conventional 24-month amortization period for the FCR under-recovered fuel
8 cost collection, I infer that the typical residential customer will pay 50% more than stated in the three year
9 test case, between \$306 and \$414 more each year – a shocking impact, made even more difficult to accept
10 given Georgia Power's *de minimis* steps to mitigate and reduce the actual fuel costs during the period.

11 Ironically, it may be in ratepayers' interests for the Commission to approve Georgia Power's
12 proposal to spread out this painful impact for ratepayers across multiple years. But it is imperative that the
13 Commission take additional steps to prevent increased pain through the higher forward-looking FCR-26
14 rate, and to take a proactive look at modernizing the Fuel Cost Recovery mechanism itself.

15 **Q: COMPARED TO OTHER UTILITIES, HOW DO YOU VIEW GEORGIA POWER'S**
16 **ACTIONS TO PROTECT RATEPAYERS FROM NATURAL GAS PRICE HIKES AND**
17 **OVERALL NATURAL GAS PRICE VOLATILITY?**

18 **A:** Over the last 30 months, advising the Pearl Street Station Finance Lab, I have participated in a
19 broad review of fuel pass through clauses across the United States. I have also closely monitored utility
20 actions during the COVID-19 pandemic period, starting in March 2020, and in response to multiple severe
21 weather events such as winter storms Uri and Elliot as well as to the geopolitical chaos in Russia and
22 Ukraine. I find Georgia Power's actions to be consistent with some of the less proactive utilities, slow to
23 respond to the ratepayer risks and reliability impacts of overreliance on natural gas. The Company's Direct
24 Testimony frequently mistakes accounting mechanisms for actual steps to reduce their fuel expenditures.²³

²² Ibid. p. 4

²³ Direct Testimony, pp. 8-9, among others.

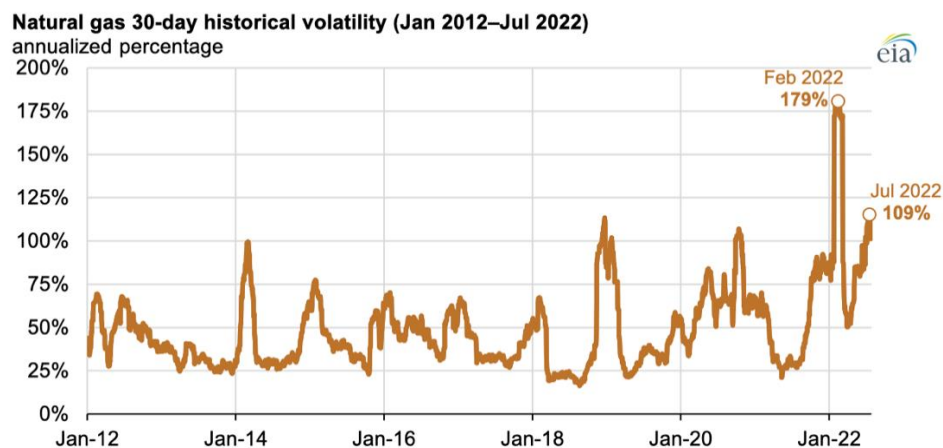
Q: WHAT IS “VOLATILITY”?

A: For commodities like gas or coal, “volatility” describes how quickly the price of a commodity changes over time. In economic and financial terms, volatility refers to the standard deviation of changes in a price variable over time. “Price volatility” does not necessarily mean that prices are increasing, or that prices are decreasing. Instead, price volatility means that prices are changing rapidly over a short period of time.

Q: CAN VOLATILITY ACTUALLY BE “UNEXPECTED?”

A: No, not anymore. Natural gas 30-day historical price volatility approached summer 2022’s price volatility index at least three times during the last decade, not including the late winter 2022 volatility spike in the wake of Russia’s invasion of Ukraine.

Chart 3



1

2 **Q: HOW WOULD YOU CHARACTERIZE GEORGIA POWER'S DESCRIPTION OF THE**
3 **DRIVERS TO THE UTILITY'S FUEL COST INCREASES?**

4 **A:** I have a lot of sympathy for their circumstances. Georgia Power does not have any meaningful
5 influence on geopolitical affairs, such as the Russian invasion of Ukraine in early 2022. Georgia Power is
6 also not directly responsible for individual severe weather events, even as we must all recognize the impact
7 of carbon emissions in driving a changed climate, including increased frequency and scale of severe weather
8 events such as hurricanes and major winter storms.

9 **Q: DO YOU AGREE THAT DEMAND AND PRICE INCREASES ARE "HIGHER THAN**
10 **EXPECTED" AND "UNPRECEDENTED?"**

11 **A:** Not really. I already discussed how natural gas price volatility cannot be reasonably described as
12 "unexpected." The number and severity of significant weather events is also not "unexpected," as the effects
13 of climate change accelerate globally, nationally, and in the Southeastern United States.

14 In June 2020, Investor advocacy organization Ceres released its updated report, "Addressing
15 Climate as a Systemic Risk: a call to action for U.S. financial regulators," yet another in a series of reports
16 detailing the quantifiable and known risks of climate-related severe events, which Ceres has released since
17 at least 2012. In its June 2020 report, Ceres stated:

18 Systemic risks have the potential to destabilize capital markets and lead to serious
19 negative consequences for financial institutions and the broader economy. Under
20 this definition, climate change, like the current COVID-19 crisis, is indisputably a
21 systemic risk. Its wide-ranging physical impacts... are likely to manifest in both
22 cumulative and unexpected ways and present clear systemic risks to U.S. financial
23 markets -- and the broader economy. Left unmanaged, these risks could have

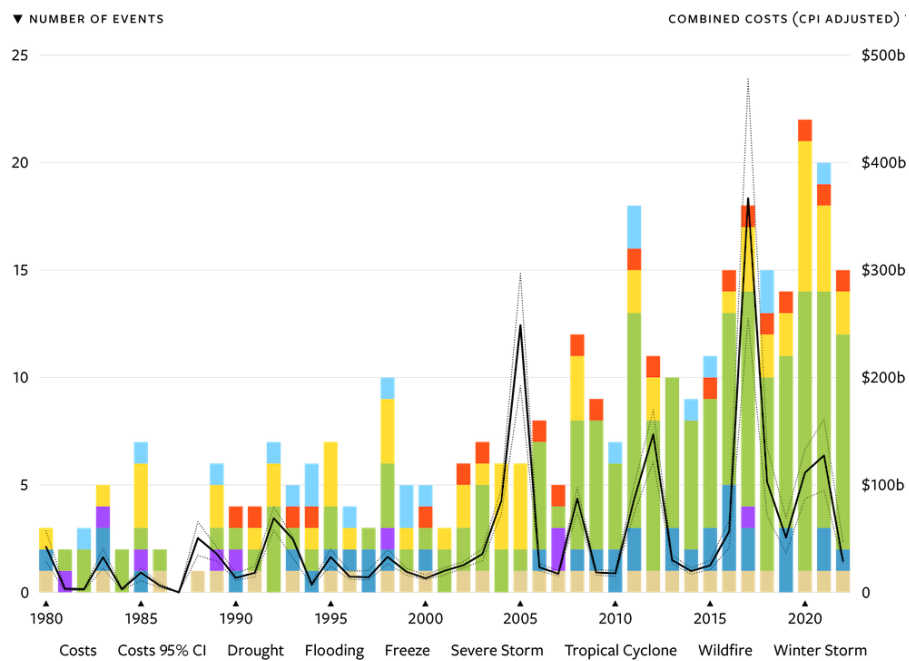
1 significant, disruptive consequences on asset valuations, global financial markets
2 and global economic stability.²⁴

3 The National Oceanographic Institute's National Centers for Environmental Information monitors
4 the number and cause of CPI-adjusted billion-dollar weather and climate-related disaster events. Since
5 1980, the United States has sustained 348 such billion-dollar disasters, including 20 winter storms and
6 freezes. Chart 4 shows the significant increase in the number, scale and scope of such major disaster events
7 in the last decade.²⁵

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23 *Chart 4 – Billion-dollar climate and severe-weather events by type since 1980*
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²⁴ Ceres, "Addressing Climate as a System Risk: a call to action for U.S. financial regulators", June 2020, <https://www.ceres.org/resources/reports/addressing-climate-systemic-risk>.

²⁵ NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2023), <https://www.ncei.noaa.gov/access/billions/>.



Georgia Power has repeatedly been warned of the volatility and risk of relying on fuel-based power generation, as recently as the 2022 IRP and PPA dockets. As intervenors SACE and Southface stated, by only focusing on natural gas and coal as supply options, Georgia Power left the Commission, and thus, the utility's ratepayers, "a choice between two volatile, risky fossil fuels, at the expense of innovative, cost controlled and less risky renewables projects."²⁶

Q: THE COMPANY STATES THAT IT DOES NOT EARN A RETURN ON FUEL COSTS. DO YOU AGREE?

A: Georgia Power is not alone in making this statement related to fuel pass through policies such as the Fuel Cost Recovery here in Georgia. That said, these statements are misleading, and do not tell the whole story.

Like nearly every Investor-Owned Utility, it is true that Georgia Power does simply pass along all of the fuel costs to ratepayers through the Fuel Cost Recovery mechanism. However, the Fuel Cost

²⁶ SACE and Southface Post-hearing brief, dockets 44160 and 44161, 2022, p. 17.

1 Recovery policy of passing along 100% of all fuel costs to ratepayers, and requiring no assumption of risk
2 or cost by the utility, results in an extraordinary situation of ratepayer risk and utility profit.

3 While Georgia Power does not make a profit or generate any return on investment for the fuel
4 purchased, they do make a profit on the power plants that burn this fuel. In Georgia, as in most cost-of-
5 service regulated states, Georgia Power's profit margin is calculated as a rate-of-return, multiplied by the
6 value of the rate-based capital assets owned by the utility. When Georgia Power owns and operates a power
7 plant, regardless of the generation technology, the utility can increase its earnings. I believe it is a general
8 axiom of electric utility economics that earning a return on the capital rate base is the principal driver of
9 Investor-Owned Utilities' shareholder earnings.

10 As a fiscally conservative former lawmaker, I have always found it useful to think about how public
11 officials – and the general public – might view a state or local government procurement process for
12 purchasing vehicles in its fleet. The government might have to choose between Option One and Option
13 Two, where Option One is a lower-initial-price truck but with lower fuel economy on a mileage-per-gallon
14 (or equivalent kWh-per-mile) basis, and Option Two is a higher-initial-price truck but with higher fuel
15 economy. Option One will be more cost-effective initially, but would ultimately cost more in taxpayer funds
16 over long-term operation. Option Two will be more expensive initially, but will save taxpayer funds over
17 long-term operation. The government procurement team will then have to determine how quickly it will
18 realize the financial benefit of Option Two, as well as whether capital expenditure fund levels are sufficient
19 to support Option Two's higher upfront cost. Further, as public stewards of both taxpayer funds and of
20 overall public health and other public goods, the government needs to determine whether other public goods
21 would be served by the higher initial cost of Option Two's greater fuel economy, including fleet reliability,
22 reduced emissions and related increased public health, and other factors. Any competitive business faces
23 similar decisions of upfront cost and long-term operational expenses, though the private-sector intangible
24 factors typically replace public goods for the business's brand improvement and reputational benefits.

25 The Fuel Cost Recovery severely distorts this budgeting and planning consideration for Georgia
26 Power and other Investor-Owned Utilities. Building and operating natural gas plants has grown Georgia

1 Power's rate base, with no risk to the utility. The Fuel Cost Recovery mechanism ensures that the utility
2 will collect all fuel costs from ratepayers, no matter the price volatility, so long as the Commission
3 determines these costs are prudently incurred. Over the years, Georgia Power has grown its capital rate base
4 of power plants, completely insulated from the risk of price volatility, particularly for the purchase of natural
5 gas and coal. This moral hazard, explained above, is not just theoretical. The consequence of the moral
6 hazard inherent in a 100% Fuel Cost Recovery mechanism within the capital-rate-based financial model is
7 that Georgia Power is able to increase its earnings base, in spite of the narrow claim that the "Company
8 does *not* earn a return on these fuel costs."²⁷

9 Not only are the costs "directly passed through to customers,"²⁸ by taking a "single-issue"
10 ratemaking approach through Fuel Cost Recovery dockets, the larger earnings base for the utility creates
11 additional inflationary pressure on ratepayers.

12 **Q: IS IT APPROPRIATE TO VIEW FUEL COST RECOVERY DOCKETS IN ISOLATION?**

13 **A:** No, I do not believe it is appropriate to review these Fuel Cost Recovery dockets without
14 understanding the interplay with other ratemaking dockets, as well as Integrated Resource Plans and
15 specific-plant Certificate of Need applications, for the reasons cited above. I believe the Commission
16 would be wise to consider the multiple factors and broader economic forces through a specific Fuel Cost
17 Recovery modernization docket. The Commission may determine that the interests of fairness require the
18 Commission to evaluate at least the FCR-25 rate recovery request under the existing Fuel Cost Recovery
19 mechanism. However, given other active dockets and Georgia Power requests in front of the Commission,
20 I believe the Commission would be wise to reassess the overall Fuel Cost Recovery approach in tandem
21 with the other dockets, and to defer decisions on the forward-looking FCR-26 upward rate adjustment.

22 **Q: TO PROTECT RATEPAYERS, DO YOU BELIEVE THE COMMISSION SHOULD**
23 **APPROVE GEORGIA POWER'S FCR-25 RATE RECOVERY REQUEST?**

24 **A:** No.

²⁷ Direct Testimony, p. 3.

²⁸ Ibid.

1 **Q: TO PROTECT RATEPAYERS, DO YOU BELIEVE THE COMMISSION SHOULD**
2 **APPROVE GEORGIA POWER'S FCR-26 TARIFF INCREASE?**

3 **A:** No.

4 **Q: IF THE COMMISSION DOES APPROVE GEORGIA POWER'S INCREASED RATE**
5 **REQUESTS NOW, WHAT SHOULD THE COMMISSION DO TO PROTECT RATEPAYERS IN**
6 **FUTURE YEARS?**

7 **A:** At the very least, I believe the Commission should initiate a docket to review all of the varied
8 policy goals and conduct a robust financial analysis of changes to the Commission's Fuel Cost Recovery
9 process.

10 **Q: IN YOUR REVIEW OF GEORGIA'S FUEL COST RECOVERY AND SIMILAR**
11 **MECHANISMS, WILL THE CURRENT UPWARD RATE REQUEST IMPACT GEORGIA**
12 **POWER'S ABILITY TO PROVIDE AFFORDABLE AND RELIABLE SERVICE?**

13 **A:** Yes. Very much so.
14

15 **IV. FUEL COST RECOVERY IMPLICATIONS FOR RELIABILITY**

16 **Q: TO PRESERVE RELIABILITY, DO YOU BELIEVE THE COMMISSION SHOULD**
17 **APPROVE GEORGIA POWER'S FCR-25 RATE RECOVERY REQUEST?**

18 **A:** From a reliability standpoint, the under-recovered fuel balance is essentially water over the dam,
19 or more accurately, money burned up the smokestack. It is not useful to assess the FCR-25 rate recovery
20 request from the paradigm of reliability.

21 **Q: TO PRESERVE RELIABILITY, DO YOU BELIEVE THE COMMISSION SHOULD**
22 **APPROVE GEORGIA POWER'S FCR-26 TARIFF INCREASE?**

23 **A:** No. More critically, approving the Georgia Power FCR-26 rate increase is likely to exacerbate
24 Georgia Power's concentrated risk as a large consumer of natural gas, and heavily reliant on natural gas
25 generation. Ms. Adams and Mr. Houston state that the coal and natural gas supply constraints of 2020 to

1 2022 “resulted in natural gas customers across the country paying higher prices for gas due to high demand
2 and limited availability for alternative fuel sources.”²⁹

3 Continuing the Fuel Cost Recovery mechanism status quo would spur Georgia Power to continue
4 to rely on natural gas generation as a primary resource, as the utility could count on recouping 100% of its
5 fuel supply costs, even in the case of renewed supply constraints, global geopolitical disruptions, and
6 ongoing price volatility.

7 **Q: EARLIER YOU STATED THAT THE CURRENT FUEL COST RECOVERY**
8 **MECHANISM HAS RELIABILITY AND HOMELAND SECURITY IMPLICATIONS. CAN YOU**
9 **EXPLAIN FURTHER?**

10 **A:** As required by the federal Department of Homeland Security’s Federal Emergency Management
11 Agency (FEMA), the Georgia Emergency Management and Homeland Security Agency (GEMA/HS)
12 maintains Georgia’s Emergency Operations Plan (GEOP). The GEOP is developed by GEMA/HS in
13 coordination with other state agencies, non-governmental organizations and private sector partners and is
14 aligned with the National Incident Management System, National Response Framework and the National
15 Disaster Recovery Framework. Every four years, GEMA/HS updates the GEOP itself and all of the GEOP
16 annexes, including Annex 12 – the Energy Annex.

17 Like all statewide Emergency Operations Plans, the GEOP takes the approach of “All Hazard
18 Planning” including identification of past and potential future emergencies in the state. The GEOP then
19 conducts a vulnerability analysis, a function of the built environment, local economy, demographics and
20 environmental uses of a region. The GEOP states very clearly that damage and/or destruction to any of
21 Georgia’s six critical lifeline sectors, including Energy, “represents enormous economic, social, and general
22 functional costs to a community, while also impeding emergency response and recovery activities.”³⁰

²⁹ Direct Testimony, p. 11.

³⁰ Georgia’s Emergency Operations Plan (GEOP), 2017 with 2019 updates, p. 6.

1 The GEOP does not mince words in describing the public health, safety and lifeline support
2 implications of events that would damage or destroy parts of the state's Energy infrastructure, particularly
3 for electrical power.³¹

4 The 2019 GEOP identified several specific "Hazards of Concern" based on past emergencies as
5 well as current and future vulnerabilities. During the period included by GEMA/HS for the GEOP, Severe
6 Weather was the most common cause of declared disaster events in Georgia, accounting for 29 of 42
7 disasters. Of these severe weather events through 2019, 4 were severe winter weather events – a Hazard of
8 Concern identified three years before winter storm Elliott wreaked havoc in Georgia, and two years before
9 Superstorm Uri created substantial natural gas price increases and subsequent price volatility for months,
10 including substantial impacts in Georgia.

11 Emergency Support Function 12 – Energy Annex supports the GEOP and provides guidance to
12 prepare for, respond to, recover from and mitigate the effects of a disaster or emergency on Georgia's
13 Energy System, and is the principal conduit by which the critical energy infrastructure is protected and
14 restored. The Commission assumes primary oversight of emergency and disaster operations pertaining to
15 electrical infrastructure, including planning and coordinating preparedness and mitigation activities
16 pertaining to electrical and natural gas infrastructures.

17 I had the honor of escorting recently retired general and flag officers, Navy SEALs, and other
18 veterans of the United States Special Forces. I recall frequent references to the need for multiple tools in
19 case of the loss or failure of one tool. One Navy SEAL officer stated often: "You have to assume that if
20 you have three tools for the job, one will break, and you will lose another one. So, what's three is really
21 two. If you have two, it's really one. And if you have just one, you're sure as done."

22 The Fuel Cost Recovery mechanism and policy of 100% pass through to ratepayers has incented
23 Georgia Power to rely far too heavily on a single source of new electrical generation: natural gas-fueled
24 power plants.

³¹ Ibid.

1
2 **V. PROPOSAL TO CHANGE INTERIM FUEL RIDER MECHANISM**

3 **Q: HOW SHOULD THE COMMISSION VIEW GEORGIA POWER'S REQUEST TO RAISE**
4 **THE INTERIM FUEL RIDER INCREASE MAXIMUM FROM 15% to 40%?**

5 **A:** With respectful skepticism. I believe the Company's proposal would negate any future need for a
6 Fuel Cost Recovery docket whatsoever. Georgia Power could rely entirely on the Interim Fuel Rider notice
7 requirements under Commission rules, thus circumventing the spirit and the letter of O.C.G.A. 46-2-26.
8 The Commission does indeed have the authority to adjust the Fuel Cost Recovery mechanism under the
9 statute, but the Commission may not actually have the authority to permit any utility to avoid the public
10 scrutiny and oversight that a Fuel Cost Recovery docket provides.

11 **Q: WHAT DO YOU MEAN BY AVOIDING PUBLIC SCRUTINY, IF THE INTERIM FUEL**
12 **RIDER CAP IS INCREASED TO 40%?**

13 **A:** Fuel Cost Recovery dockets include an opportunity for the Commission to determine whether
14 utility fuel expenses are the result of "illegal or clearly imprudent conduct on the part of the utility," in
15 which case the Commission is obligated to disallow such fuel cost recovery by the utility.³² I do not see
16 how the Commission could exercise its obligation if the Interim Fuel Rider maximum adjustment is higher
17 than the current 15%, permitting the utility to avoid any needed Fuel Cost Recovery docket going forward.

18
19 **VI. APRIL 12, 2023, STIPULATION**

20 **Q: DID YOU REVIEW THE STIPULATION AGREEMENT BETWEEN GEORGIA POWER**
21 **AND THE COMMISSION'S PUBLIC INTEREST ADVOCACY STAFF?**

22 **A:** Yes, as well as the Attachment A related to the Interim Fuel Rider mechanics.

23 **Q: DOES THE STIPULATION AGREEMENT SOLVE THE ISSUES RAISED IN YOUR**
24 **TESTIMONY?**

³² O.C.G.A. 46-2-26(h).

1 **A:** No, it does not. The Stipulation would only reduce the Company’s approximate \$2,520,000,000
2 under-recovered fuel balance by \$7,000,000, retaining 99.72% of Georgia Power’s original request under
3 this docket. Further, the Stipulation does not address the significant negative consequences of increasing
4 the Interim Fuel Rider cap to 40%.

5 I do not see any reason to modify my description of the docket, amended by the Stipulation, as
6 “shocking.”

7 **Q: SHOULD THE COMMISSION APPROVE THE DOCKET AS AMENDED BY THE**
8 **PROPOSED STIPULATION AGREEMENT?**

9 **A:** No. My overall recommendation has not changed after my review of the Stipulation documents.
10

11 **VII. COMMISSION DOCKET ON MODERNIZING FUEL COST RECOVERY**

12 **Q: WHAT SHOULD THE COMMISSION CONSIDER IN A FUEL COST RECOVERY**
13 **MODERNIZATION DOCKET?**

14 **A:** I believe the Commission should follow other states, such as Missouri and Idaho, among others, in
15 pursuing a modernized sharing of fuel costs and fuel risk between the utility and its ratepayers. Such Fuel
16 Cost Recovery reforms require balancing utility shareholder concerns against ratepayer protection; ensuring
17 reliability and mitigation of emissions, and achieving transparency alongside reasonable business
18 considerations.

19 I believe the Commission can best consider these issues in a holistic fashion through a specific
20 docket focused on modernizing the Commission’s Fuel Cost Recovery mechanism, including a reasonable
21 amount of risk to be assumed by utilities.

22 As laid out in the Primer on Fuel-Cost Pass-Through Reform, such a docket should address these
23 factors:

- 24 1. **The proper amount of fuel cost sharing and fuel risk sharing to be assigned to the**
25 **utility.** There is not one “best” sharing amount that should be applied to all utilities
26 because utilities vary in multiple ways. Each utility relies on different mixes of fuel-

1 and non-fuel generation sources, and each utility faces different risk profiles in their
2 jurisdictions.

3 2. **Symmetrical or asymmetrical incentives and penalties.** A symmetrical fuel-cost
4 sharing assigns the same percentage of fuel risk and fuel cost responsibility to the
5 utility regardless of whether the actual fuel costs are higher or lower than expected. An
6 asymmetrical mechanism shares a different amount in each case. Both symmetrical
7 and asymmetrical sharing can be structured to provide both rewards and penalties.

8 3. **Straight sharing of fuel costs and risks, or the use of “deadbands.”** The simplest
9 structure for a fuel-cost sharing mechanism is to always require the same level of utility
10 fuel cost responsibility (e.g., 10 percent) regardless of how much the utility’s actual
11 costs deviate from expectations or forecasts. A “deadband” approach can ensure that
12 risk-sharing and cost-sharing changes the greater utility’s actual costs have deviated
13 from expectation or forecast. For instance, with respect to natural gas price volatility,
14 the deviation from forecasted gas prices was significant enough over the past three
15 years to merit some adjustment to a risk-sharing formula; the Commission would be
16 able to evaluate different scenarios through modeling in a modernization docket.

17 4. **Reliance on forecasts versus actual historic pricing.** Forecasting natural gas pricing
18 can feel like an exercise in futility. Some states, such as my home state of Minnesota,
19 have adjusted the timing of fuel cost reviews to ensure greater reliability of actual
20 pricing and costs, given the challenge of reliable forecasting.

21 5. **Transparency of key contract terms.** Georgia’s current Fuel Cost Recovery rules
22 require some disclosure of fuel supply agreement terms. But I believe that some critical
23 contract terms can still be treated as confidential trade secret information, such as
24 minimum delivery amounts (“take or pay” provisions), automatic price increases and
25 others.

- 1 6. **Review for Prudence.** The Commission may find that it has ample authorization under
2 the current FCR mechanism to properly review utility acts to ensure they address
3 known or foreseeable risks that can result in shocking rate impacts as proposed in this
4 docket. Any modernization effort should ensure that this prudence review continues.
- 5 7. **Hedging.** As the Company implies in the current docket, a utility can purchase stability
6 and price predictability in exchange for a premium payment for such future fuel supply.
7 Hedging is currently a permitted strategy by Georgia Power to address price risk – at
8 an initial cost to its ratepayers. The Commission should evaluate the use of hedging as
9 a cost-effective strategy over decades, and not just in times of geopolitical turmoil and
10 a global pandemic.
- 11 8. **Purchased Power.** Georgia's Fuel Cost Recovery mechanism currently ensures that
12 the fuel costs of purchased power are included in the utility's fuel rate calculations.
13 Any risk-sharing and cost-sharing proposal should consider continuing this policy
14 component, lest a utility attempt to sidestep the fuel risk requirements strictly through
15 Power Purchase Agreements rather than utility-owned assets.
- 16 9. **Integrating Fuel Sharing in Other Ratemaking.** Fuel cost recovery has become a
17 form of single-issue ratemaking that even Georgia Power admits could become more
18 than 36% of the total revenue collected via ratepayers' bills.³³ Fuel costs and fuel risk
19 continue to be critical factors in utility Integrated Resource Plans. Modernizing Fuel
20 Cost Recovery in Georgia will make for a more efficient and consistent resource
21 review across multiple dockets and multiple factors.

22 **Q: IS THERE AN OPTIMAL AMOUNT OF UTILITY RESPONSIBILITY THAT THE**
23 **COMMISSION SHOULD CONSIDER?**

³³ MFRP 1-1.

1 **A:** I do not believe it is worthwhile to even consider returning to the pre-OPEC days of assigning to
2 the utility 100% of fuel cost and fuel risk responsibility. Fuel risk sharing efforts in Hawaii, Idaho and other
3 states suggest that sharing even 10% of fuel risk and fuel costs with the utility can have a dramatic benefit
4 for reliability, resource diversity, ratepayer protection and utility performance.

5 **Q: DOES THE UTILITY HAVE ANYTHING TO GAIN BY ACCEPTING FUEL RISK-**
6 **SHARING AND FUEL COST-SHARING?**

7 **A:** Absolutely. When designed well, a modernized fuel-sharing policy will provide utilities with a
8 form of a performance incentive mechanism. If the utility can actively reduce fuel risks and fuel costs, as
9 determined in a Fuel Cost Recovery docket, the utility should be rewarded for such efforts. The total fuel
10 risk and fuel cost savings to the ratepayer should exceed any additional earnings awarded to the investor-
11 owned-utility, of course. But designed well, a modernized Fuel Cost Recovery mechanism in Georgia will
12 provide consistent benefits to the utility and to ratepayers.

13
14
15 **CONCLUSION**

16 **Q: PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.**

17 **A:** 1. In the matter of the FCR-25 tariff under-recovered fuel balance, the Commission should
18 rigorously review the prudence of Georgia Power's actions. While Georgia Power could not have predicted
19 the specific events that contributed to the under-recovered fuel balance, multiple experts warned of the risks
20 of excessive reliance on natural gas and the ongoing price volatility of natural gas even without winter
21 storm Uri and Russia's invasion of Ukraine. Georgia Power could have taken any number of prudent steps
22 to minimize its exposure to natural gas price volatility.

23 2. The Commission should not approve the forward-looking FCR-26 fuel rate adjustment. The
24 Commission should instead initiate a Fuel Cost Recovery modernization docket to include some amount of
25 fuel-cost-sharing and fuel-risk-sharing by the utility, to mitigate the moral hazard under the current policy
26 of passing through 100% of fuel costs to ratepayers. The Commission has the authority under the Fuel Cost

1 Recovery statute -- because of Georgia Power's failure to take sufficient prudent steps -- to make
2 amendments that would better allocate risk and costs between utilities and ratepayers. A modernization
3 docket is the best means to evaluate all the policy options, relevant factors and potential impacts.

4 3. Georgia Power's proposal to increase the Interim Fuel Rider maximum adjustment to 40%
5 without Commission review risks violating the Commission's statutory responsibility to conduct a
6 prudency review of Georgia Power's fuel costs. The Commission should reject this proposal.

7 4. Georgia Power's proposals also risk the utility's strong prior record on reliability. Addressing
8 Fuel Cost Recovery tariffs without considering the impact of other ratemaking dockets has led to unintended
9 consequences, including an outsized reliability on natural gas. Other non-fuel alternatives could have
10 mitigated the multi-billion-dollar impact to ratepayers.

11 5. The Commission should not accept the proposed April 12, 2023, Stipulation between Georgia
12 Power and the Georgia Public Service Commission Public Interest Advocacy Staff, as it does not materially
13 address the issues raised in this testimony.

14
15 **Q: DOES THIS COMPLETE YOUR TESTIMONY?**

16 **A:** Yes. Thank you.

JEREMY KALIN

901 MARQUETTE AVE SO, SUITE 1675 MINNEAPOLIS, MN 55402 • 612.584.3400 • JKALIN@AVISENLEGAL.COM

EDUCATION

- J.D. **William Mitchell College of Law**, St. Paul, MN.
University of New Mexico, School of Architecture and Planning, Albuquerque, NM.
- B.F.A. **University of Minnesota**, Minneapolis, MN.

PROFESSIONAL EXPERIENCE

- Attorney and Shareholder, Avisen Legal P.A.** 2019 - present
- Impact Counsel practice focused on low-carbon project finance and early-stage investment. Practice areas include energy policy; climate finance and related impact investment; solar electricity and energy efficiency; greenhouse gas reduction and related projects.
 - Clean energy financing and impact investment consulting for underserved and untapped markets in clean energy, clean water and green infrastructure.
 - General Counsel for venture capital funds investing in technology companies.
 - Admissions: Minnesota and the District of Columbia.
- Kalin LLC, Principal** 2017 - present
- Clean energy financing and impact investment consulting for underserved and untapped markets in clean energy, clean water and green infrastructure.
 - Built and launched multiple award-winning low- and moderate-income solar finance platforms for U.S. Department of Energy.
 - Built and launched Credit Unions' CU Green® clean energy investment platform.
- Senior Advisor, National Caucus of Environmental Legislators (NCEL)** 2016 - present
- National, bipartisan non-profit organization supporting state lawmakers advancing clean energy and resilient communities policies across all 50 states.
- Senior Advisor, GOVERNING Institute** 2014 - 2020
- Advisor and Speaker on Infrastructure, Workforce and Clean Energy Economy
- Eutectics®, CEO** 2010 - 2018
- Nationally-recognized, mission-driven clean energy finance consulting firm with over \$273 Million in projects in progress or completed nationwide.
 - Clients include: U.S. Department of Energy; City of Morris (MN); Baltimore City (MD); Chisago County HRA-EDA; Philadelphia (PA) Energy Authority; St. Paul PHA; The Nature Conservancy; University of Minnesota; etc.
- State Representative, Minnesota House of Representatives District 17B (Chisago County)** 2007 - 2011
- **Coalition of Legislators for Energy Action Now (CLEAN), Chair;** Obama White House bipartisan task force of legislative leaders on clean energy and climate policy.
 - **Minnesota Green Jobs Task Force, Co-Chair.**
 - **Legislative Chief Author:** 2010 Property Assessed Clean Energy (PACE) Act; 2009 Green Jobs Act / ARRA Energy Appropriation; 2008 Military and Overseas Voter Act; 2007 Demand Efficiency Act (*selected legislation*).
- Vice-Chair, East Central (MN) Regional Development Commission** 2004 - 2006
- Vice-Chair and Chisago County Representative on regional economic development authority serving Pine, Isanti, Chisago, Kanabec and Mille Lacs Counties.

SELECTED COMMUNITY SERVICE

Mississippi Headwaters Fund Advisory Board , The Nature Conservancy	2016 – 2018
The Violence Project Research Center , Board Member	2020 - present
Safety and Security Committee Chair , Shir Tikvah Synagogue	2018 - present
Jewish Family and Children's Service of Minneapolis , Director	2013 - 2021
Capital Expansion Working Group, Innovative Housing Network , Chair	2016 - 2017
FBI Citizens Academy , Minneapolis Division	2018
Minnesota Chamber of Commerce , Energy Policy Committee	2014 - 2016
State Innovation Exchange (SiX) , Founding Advisory Board	2012 – present
Overseas Vote Foundation , Advisory Board	2009 - 2012
James J. Hill Business Reference Library , Board Member	2010 – 2012
Chisago County (MN) Land Use Coalition	2004 - 2006
East Central (MN) Arts Council	2004 – 2006

SELECTED AWARDS AND RECOGNITION

Royal Society of the Arts , Fellow	2018 - present
British American Project , Fellow	2014 - present
Progress Minnesota 2017 Honoree (Eutectics)	2017
Midwest Energy Efficiency Alliance , Inspiring Leadership Award	2008
Legislator of Distinction , League of Minnesota Cities	2008
Legislative All-Star , Fresh Energy Minnesota	2007
Graduate Teacher of the Year , University of New Mexico, School of Architecture and Planning	2003

TEACHING EXPERIENCE

University of Minnesota , College of Design, “Design Thinking for Public Policy”
University of New Mexico , Graduate Teaching Assistant, School of Architecture and Planning
Massachusetts College of Art , Visiting Faculty
University of Minnesota College of Liberal Arts , Art Department, Teaching Assistant

SELECTED RECENT SPEAKING APPEARANCES

IMPACT , United States Green Building Council, Minnesota
American Institute of Architects , National Conference
Minnesota Real Estate Journal , Energy Summit
National Press Club , GOVERNING Outlook
United States Senate , Climate and Energy Security briefing
Center for Climate Strategies Forum on State and Subnational Leadership , United Nations Conference of Partners (COP15), Copenhagen, Denmark
University of Minnesota , College of Design, Commencement Speaker
National Press Club , United States Green Building Council Green Schools Caucus national launch
The White House , State Leadership on Clean Energy

Energy Efficiency Finance Forum, American Council for an Energy Efficient Economy
Georgetown University Climate Center, State Leadership on Climate and Energy
Good Jobs, Green Jobs Conference, Blue-Green Alliance Conference
Midwest Energy Solutions Conference, Midwest Energy Efficiency Alliance

SELECTED RECENT ARTICLES

Learning to Share: A Primer on Fuel-Cost Pass-Through Reform, Pearl Street Station Finance Lab, April 2023

Commentary: Clean Energy Still Trumps Partisan Politics, Midwest Energy News, November 2016

Sustainable: The Business Case for Going Green, Finance & Commerce, June 2016

Minnesota Community's Energy Focus Gives It Edge in National Competition, Midwest Energy News, June 2016

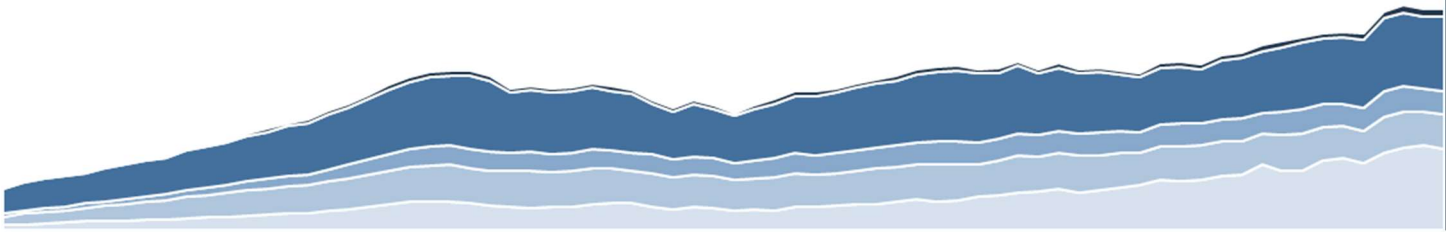
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Energy Finance Advisor Helps Businesses Go Green, Minneapolis Star Tribune, October 2014

PACE Creating Efficiency Opportunities, Midwest Energy News, June 2014

'SolarNote' Aims to Reduce Complexity in Financing, Finance & Commerce, February 2014

From Commodity to Service: Why the Capitalization Model for Electric Regulation is Failing Minnesota, J.D. thesis paper, June 2010



LEARNING TO SHARE: A PRIMER ON FUEL-COST PASS-THROUGH REFORM

Authors: Albert Lin, Jeremy Kalin, and Kaja Rebane.

Albert Lin is the Executive Director of Pearl Street Station Finance Lab (PSS FL).

Jeremy Kalin is an Attorney in Avisen Legal's Impact Council Practice, and a consultant to PSS FL.

Kaja Rebane is a Senior Associate in RMI's Carbon-Free Electricity Practice.

Acknowledgements:

This report was made possible by the generous support of Energy Foundation.

We would like to thank Rachel Gold (RMI) and Joe Daniel (RMI) for their thoughtful review of this work and Liza Martin (Independent Contractor) for editing expertise.

Organizational affiliations are listed for identification purposes only. The opinions expressed herein do not necessarily reflect those of the organizations that funded the work or the individuals who reviewed it. Pearl Street Station Finance Lab bears sole responsibility for the report's content.

April 5, 2023

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Executive Summary

Electric utilities in the United States spend billions of dollars annually buying fuel to generate electricity. These costs often make up a sizable share of customer bills, and unlike other bill components, they can vary substantially from month to month. This makes it imperative that utilities manage their spending on fuels carefully—but most utilities have no financial incentive to do so. This is because in most states today, utilities are allowed to pass on 100 percent of their actual spending to customers through policies called “fuel adjustment clauses” (FACs).

FACs create a problem that economists call “moral hazard.” Moral hazard exists when one party does not suffer the consequences of making bad decisions, so it takes bigger risks as a result. Current 100 percent pass-through policies create moral hazard because if utilities manage to reduce fuel costs (for example, by negotiating better prices or reducing their fleet’s reliance on fuel) their customers receive all of the benefits, and if utilities manage their costs poorly, their customers pick up the bill.

Ever since FACs were implemented, they have created this moral hazard problem. However, in recent decades its real-world consequences have grown more acute due to a series of developments. These include several trends which have magnified the risks of heavily relying on price-volatile fuels for electricity generation, and others which have decreased the cost of fuel-free alternatives. In addition to the heavy cost burden that FACs impose on today’s customers, they also fail to incentivize utilities to properly consider low- and no-fuel options that could help lower carbon emissions.

Though FACs are the norm today, these policies are ripe for revision by legislators and public utility commissioners interested in addressing these growing challenges. However, not all policy makers understand the downsides of current FAC policies, and not all those who do are motivated to take proactive actions to address them. Advocates can play important roles in educating key policymakers, encouraging them to act, and enlisting the support of other parties when needed to advance reforms in their state.

Eliminating FACs altogether may seem like the simplest policy fix, but moving from a 100 percent pass-through to a zero-percent pass-through overnight could create financial difficulties for utility companies. Fortunately, such an abrupt change is not necessary. Updating the FAC to pass through a lower share of the utility’s actual spending to customers can successfully address the moral hazard problem while limiting the total risk the utility is exposed to. This type of reform is called “fuel-cost sharing.”

Fuel-cost sharing can be implemented in different ways. The basic fuel-cost sharing policy that has been adopted by most states to date represents only a modest departure from the status quo. It entails first building a forecast of fuel costs into the utility’s base rates (as is true of FAC policies), and then truing up less than 100 percent of the difference between the forecasted and actual spending. However, this is not necessarily the optimal design, since relying on forecasts makes this approach vulnerable to gaming by the utility. FAC reforms can also be designed in other ways that may better serve local policy priorities.

A range of design considerations are relevant. These include the extent of fuel-cost sharing, whether the sharing is symmetrical, and which costs are included in the mechanism. Other policies can also

be used to complement the fuel-cost sharing mechanism or serve as alternatives to it, including reforms that increase transparency, encourage hedging, and increase the scrutiny of utility spending decisions.

While FAC policies remain the norm across the United States today, a few states have adopted fuel-cost sharing policies or other reforms. These include Hawaii, Idaho, Oregon, Wyoming, Montana, Washington, Wisconsin, Vermont, and others.

Reforming FAC policies could enhance affordability by motivating utilities to manage their fuel costs more carefully. It could also reduce carbon emissions by encouraging utilities to switch more quickly to fuel-free technologies. It is time for these outdated policies to change, and both commissions and advocates can play important roles in advancing reforms.

Introduction

Every year in the United States, electric utilities spend billions of dollars purchasing fuel to generate electricity. During the COVID-19 pandemic, between 2020 and 2021, vertically integrated utility companies alone spent \$70 billion in fuel costs.¹ This represents a sizable share of the total cost of producing electricity.

However, thanks to an obscure policy commonly known as the “fuel adjustment clause” (FAC), most US utilities lack any financial incentive to reduce how much money they pay for fuel.² Instead, these utilities are allowed to “pass through” 100 percent of these costs to their customers via a bill rider. Customers then have little choice but to pay for these costs—since the alternative would be to lose their access to electricity. In many states, the FAC is a specific line item on electric utility bills, as illustrated in Figure 1.

Figure 1. Sample Electric Bill from Xcel Energy

ELECTRICITY CHARGES		RATE: Net Energy Billing Svc	
DESCRIPTION	USAGE UNITS	RATE	CHARGE
Basic Service Chg			\$8.00
Basic Service Chg			\$1.90
Energy Charge Winter	946 kWh	\$0.088030	\$83.28
Energy Charge Winter	0 kWh	-\$0.121590	\$0.00
Fuel Cost Charge	946 kWh	\$0.035507	\$33.59
Sales True Up	946 kWh	-\$0.007360	-\$6.96 CR
Affordability Chrg			\$0.98
Resource Adjustment			\$14.23
Interim Rate Adj			\$8.14
Subtotal			\$143.16
City Fees		5.00%	\$7.06
Transit Improvement Tax		0.50%	\$0.74
City Tax		0.50%	\$0.74
County Tax		0.15%	\$0.23
State Tax		6.875%	\$10.20
Total			\$162.13
Premises Total			\$162.13

A FAC often appears as a separate line item on customer electricity bills. It is highlighted on this residential bill from Minnesota.

The burden on customers is further increased by the variability of fuel costs. Unlike most components of utility bills, the size of the fuel charge fluctuates substantially over time. This is largely due to the volatility of natural gas prices (and to a lesser extent, coal prices) coupled with changing weather. For example, in January 2022, fuel-cost volatility combined with Kentucky

¹ Albert Lin and Joe Daniel, Electricity Customers are Getting Burnt by Soaring Fossil Fuel Prices, RMI, June 23, 2023, www.rmi.org/electricity-customers-are-getting-burnt-by-soaring-fossil-fuel-prices

² Fuel costs are passed through to customers via FACs by both electric utilities and natural gas utilities. While this primer focuses specifically on electric utilities, many of the same arguments for FAC reform apply to gas utilities as well. We refer to policies that pass 100 percent of fuel costs through to customers via a bill rider as “fuel adjustment clauses” (FACs), but in some states these policies go by different names (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

Power's FAC resulted in “roller coaster” rates that made it difficult for some customers to make ends meet.³ Figure 2 illustrates the volatile nature of natural gas prices over the last decade.

Figure 2. Historical Price Volatility of Natural Gas

Natural gas 30-day historical volatility (Jan 2012–Jul 2022)

annualized percentage



Natural gas prices are highly volatile. Though the price spike in early 2022 was particularly severe, gas prices continually rise and fall in unpredictable ways.⁴

Though FACs pass through 100 percent of actual costs to customers, most components of utility rates do not work this way. The basic rates utilities charge customers for electric service (known as base rates) are set in advance according to the projected costs of power generation and delivery over a set period of time. These base rates establish a predictable per-kWh rate, even if utilities spend more or less than was expected when the rates were set.

In contrast, a FAC allows a utility to charge customers for the exact amount spent on fuel. As a result, fuel does not represent a business cost or profit center for utility companies. This means utilities are able to ignore the cost and volatility of fossil fuels in their decisions, even though customers end up paying more as a result.

Allowing utilities to ignore the consequences of relying on fuels distorts decision-making about what types of resources to invest in, which can disadvantage fuel-free resources in utility planning and investment decisions. Since earnings are not affected if fuel prices rise, the utility can ignore the risk of volatile and elevated costs when making investment decisions. Ignoring the volatility of fossil fuels tips the scales towards them—and away from more cost-effective fuel-free alternatives like wind, solar, and energy efficiency. FACs also give utilities no incentive to find shorter-term strategies to lower fuel costs, such as negotiating better fuel-supply contracts.

This phenomenon differs from what happens in a competitive market, where a company that succeeds in reducing its costs will gain an advantage over its competitors. A regulated utility with a

³ Emily Bennett, WSAZ Investigates: Kentucky Power bill spike, January 28, 2022, <https://www.wsaz.com/2022/01/28/wsaz-investigates-kentucky-power-bill-spike>

⁴ Figure from EIA, U.S. natural gas price saw record volatility in the first quarter of 2022, August 24, 2022, <https://www.eia.gov/todayinenergy/detail.php?id=53579>

FAC gains nothing if it succeeds in reducing its fuel costs. Because of this 100 percent pass-through policy, a utility that manages its fuel costs well earns no reward—and one that manages them poorly faces no consequences because its customers pick up the bill.

History of Fuel-Cost Pass-Through Policies

Fuel costs were not always treated as a 100 percent pass-through to utility customers. For almost the whole first century of US utility regulation, utilities were expected to manage their fuel costs in the same fashion as other business expenses.

“Because of this 100 percent pass-through policy, a utility that manages its fuel costs well earns no reward—and one that manages them poorly faces no consequences because its customers pick up the bill.”

The first power plants were built in the last few decades of the 19th century. To prevent privately owned utilities from overcharging customers, local and state governments stepped in to regulate the rates they could charge. The newly created public utility commissions treated fuel costs as just one aspect of the costs of doing business, rather than as a unique cost category requiring special ratemaking treatment.⁵

When World War I caused fuel prices to soar, utilities lobbied commissions for relief from fuel-price volatility and the associated risk of significant financial loss. Public utility commissions responded by implementing the first temporary FACs, which they discontinued shortly after the war. When World War II also created global fossil-fuel supply challenges, commissions reinstituted temporary FACs—which were likewise curtailed once peacetime resumed.

The oil shocks of the 1970s again sparked utility demands for insulation from global supply disruptions, and this time both state legislators and public utility commissions responded. Though the gasoline lines of the 1970s soon disappeared, in most states the statutes and commission decisions that established FACs have never been meaningfully revisited.

Today, these policies are the norm across the country. In most states, the process through which costs are approved for recovery through FACs is opaque to customers and their advocates, since investor-owned utilities are allowed to treat their fuel-supply agreements as trade secrets. This means that despite being saddled with 100 percent of the costs, ratepayers cannot generally evaluate whether the fuel-supply agreement terms are reasonable.

It is reasonable to wonder why legislators and public utility commissions have left these policies in place for so long. FACs are typically justified based on the idea that utilities cannot control the cost of fuel. However, this assertion was never entirely true, and it is even less true today. For example, utilities make decisions about how much natural gas capacity to build, and they negotiate the fuel-supply contracts that determine the prices they pay for natural gas. In addition, due to technological

⁵ We refer to all such regulatory bodies as “public utility commissions.” In many states the body has a similar name (e.g., the Nevada Public Utilities Commission), but this is not always the case (e.g., the Maryland Public Service Commission, the Kansas Corporation Commission, the Washington Utilities and Transportation Commission).

advances, utilities can now displace fuel-based generation with a range of cost-competitive alternatives that use little to no fuel (e.g., solar, wind, batteries, energy efficiency). Yet, because FACs insulate utilities from the financial consequences of relying on fuel, the companies have little incentive to change.

The Problem: Moral Hazard and Inefficient Investment Decisions

FACs create a problem that economists call “moral hazard.” Moral hazard exists when one party does not suffer the consequences of making bad decisions, so they may take bigger risks as a result. The moral hazard problem crops up in many spheres, including insurance, investing—and utility regulation.⁶

In the regulatory sphere, 100 percent fuel-cost pass-through policies provide a particularly stark example of moral hazard. When a FAC is in place, the utility decides how much fuel to buy and at what price—but it is the utility’s customers who pay the cost if the utility spends more money than necessary. In other words, the utility (and its shareholders) are held harmless from the consequences of poor fuel-management decisions.

The moral hazard problem has existed since the first FACs were implemented; however, in recent decades, the real-world consequences of this have grown more acute. This is due to two types of recent trends. First, a series of developments have magnified the risks of relying heavily on fuels. Second, the costs of fuel-free alternatives have decreased.

“The moral hazard problem has existed since the first FACs were implemented; however, in recent decades the real-world consequences of this have grown more acute.”

Trends that Have Magnified the Risks of Relying Heavily on Fuels

The first category is developments that have increased the risks associated with relying on fuels. These include the following:

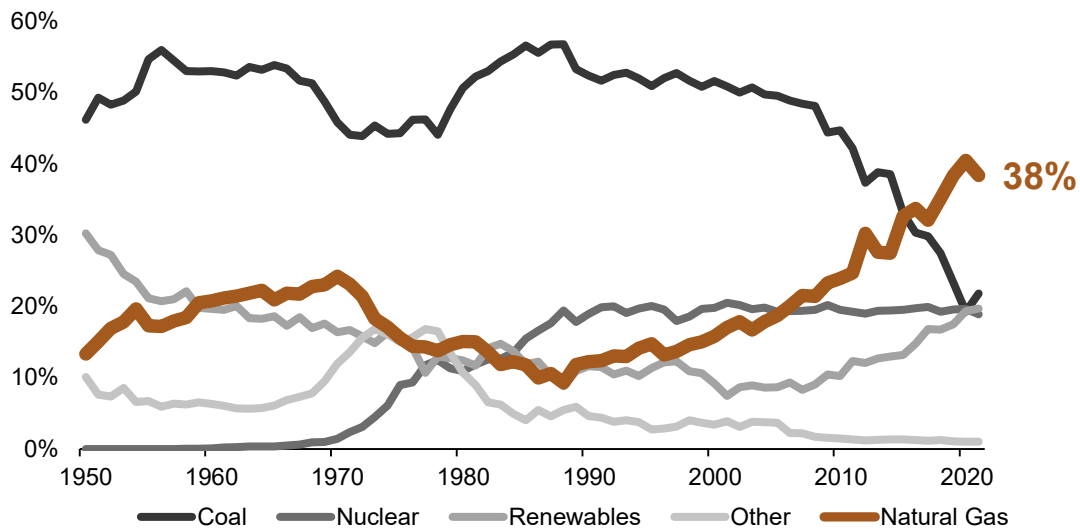
Greater utility dependence on natural gas. Over the last two decades, utilities have been building gas-fired power plants at a rapid pace. Because of this construction spree, the share of electricity generated from gas has risen dramatically (Figure 3), and electric utilities have grown from being small, niche buyers of natural gas to being the gas industry’s biggest buyers (Figure 4). This has created a situation in which customers are much more exposed to the effects of gas-price volatility than they used to be. Natural gas prices are by their nature volatile, and now a much higher share of electricity generation depends on gas purchases.⁷ In addition, the electric sector’s demand tends to rise and fall in a pattern driven by seasonal

⁶ The classic insurance example is that an insured party may take more risks than they would otherwise, since the insurer will pay for any loss that may occur. An example from the world of investing is that a money manager may take excessive risks with other people’s wealth.

⁷ Jamison Cocklin, U.S. Natural Gas Price Volatility at All-Time High in 2022, Natural Gas Intelligence, August 16, 2022, <https://www.naturalgasintel.com/u-s-natural-gas-price-volatility-at-all-time-high-in-2022>

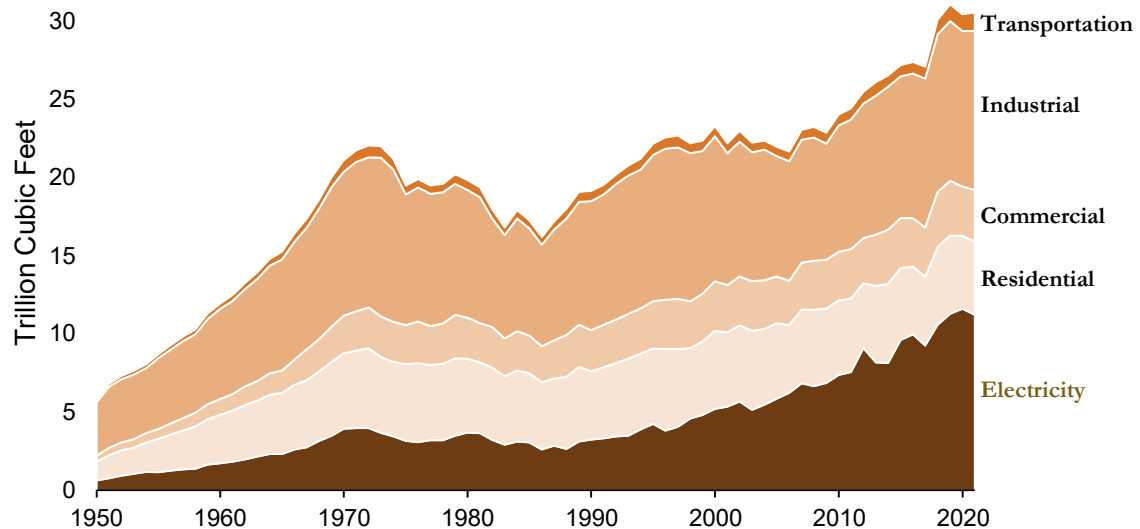
changes and regional weather events—which can cause supply constraints. For example, if a major heat wave hits the eastern United States, the electric utilities in all impacted states will consume more natural gas than usual to meet the increased need for air conditioning, resulting in rapid price increases as regional gas inventories are depleted.

Figure 3. US Electricity Generation by Resource



Between 1950 and 2022, the share of electricity generated from natural gas roughly tripled, from 13 percent to 38 percent.⁸

Figure 4. US Natural Gas Consumption by Sector



In recent years, the electric power sector has become the largest customer of the natural gas industry.⁹

⁸ Data from EIA, February 2023 Monthly Energy Review, Table 7.2a, <https://www.eia.gov/totalenergy/data/monthly>

⁹ Data from EIA, February 2023 Monthly Energy Review, Table 4.3, <https://www.eia.gov/totalenergy/data/monthly>

More severe weather. Another recent trend is that weather is becoming more severe due to climate change. The growing intensity of both summer heat waves and winter cold snaps increases the odds of large fuel-price spikes as gas demand outstrips available supply. For example, in 2021, Winter Storm Uri led to a steep drop in natural gas production, leading to supply constraints and record-setting prices.¹⁰ Forest fires, hurricanes, and even seasonal weather events can also trigger fuel-supply disruptions that translate into price volatility.

Increasing exposure to geopolitical risks. Globalization has made the international economy increasingly interconnected. With heightened natural gas prices in Asia and Europe, US producers ship a sizable share of domestically produced gas abroad as liquified natural gas (LNG)—and the United States recently became the world’s largest LNG exporter.¹¹ This heavy involvement in international trade makes the US natural gas sector vulnerable to conflict-induced supply disruptions, which can translate into increased fuel-price volatility. For example, when Russia invaded Ukraine in February of 2022, the combination of sanctions against Russian gas and increased exports to Europe caused global prices for natural gas to soar.¹²

Trends that Have Made Fuel-Free Alternatives More Attractive

In addition to the trends magnifying the risks of relying heavily on fuels for electricity generation, a series of developments have made fuel-free alternatives more reliable and cost-effective. These include the following:

Cheaper fuel-free alternatives. Through the end of the twentieth century, most commercially viable generation technologies (e.g., coal, natural gas, nuclear) required fuel. Today, fuel-free energy resources like energy efficiency, solar, and wind are often the lowest-cost sources of power,¹³ while new technologies like advanced metering infrastructure (AMI) and distributed energy resource management systems (DERMS) can enable storage, energy efficiency, and demand response to be deployed in ways that allow a much higher share of demand to be met by these resources.¹⁴ Utilities today can choose to reduce fuel dependence in ways that were not possible even a few years ago.

Supportive federal policies. The Inflation Reduction Act (IRA), passed in 2022, featured a range of provisions that increased the economic attractiveness of fuel-free alternatives. These include the extension of the production tax credit (PTC) and investment tax credit (ITC) that are available to renewable and storage facilities, changes that better position

¹⁰ American Public Power Association, Winter Storm Uri, Extreme Winter Events, And Natural Gas Reforms, Issue Brief, January 2022, <https://www.publicpower.org/system/files/documents/January%202022%20-%20Winter%20Storm%20Uri.pdf>

¹¹ EIA, The United States became the world’s largest LNG exporter in the first half of 2022, July 25, 2022,

¹² IEA, Russia's War on Ukraine: Analysing the impacts of Russia's invasion of Ukraine on global energy markets and international energy security, <https://www.iea.org/topics/russias-war-on-ukraine>

¹³ Zachary Shahan, Wind & Solar Are Cheaper Than Everything, Lazard Reports, CleanTechnica, November 15, 2020, <https://cleantechnica.com/2020/11/15/wind-solar-are-cheaper-than-everything-lazard-reports>

¹⁴ Lauren Schwisberg, The Business Case for New Gas Is Shrinking, RMI, December 8, 2022, <https://rmi.org/business-case-for-new-gas-is-shrinking>

regulated utilities to take advantage of these tax credits, and access to low-cost debt to help retire existing fossil-fired power plants.¹⁵

The Consequences of Moral Hazard Have Grown More Acute

Taken together, these recent trends have fundamentally changed the US energy landscape. The risks of overreliance on fuel-based generation have increased while fuel-free alternatives have become more reliable and cost effective. In the present world, it literally pays to reduce utilities' reliance on fuel, but it is the customer not the utility that benefits from those cost reductions.

While a utility doesn't profit from using more fuel, it doesn't profit from decreasing fuel usage either. It's also important to realize that managing fuel costs carefully isn't free. It takes managerial effort and investment in expertise, and utility managers are incentivized to focus on other areas of operations and investment. Because of this, utilities are not taking full advantage of current opportunities to reduce fuel costs. Fortunately, a practical solution to this moral hazard problem is available. We turn to this next.

A Promising Solution: Fuel-Cost Sharing

FACs are the norm today, but this can be changed. These outdated policies are ripe for revision by legislators and public utility commissioners who care about making utility services more affordable, protecting customers from unnecessary risks, and/or reducing carbon emissions. The moral hazard created by 100 percent pass-through policies undermines all of these goals. Updating these policies can yield multiple benefits by motivating the party that is best positioned to reduce fuel costs to use its information, abilities, and skills to do so.

Since FACs have only been the norm for a few decades, it may seem like the best solution would be to eliminate them altogether. However, such a marked departure from current practice could pose significant risks. Today's utilities would be more sensitive to unexpected fuel-cost fluctuations than their early 20th-century counterparts, since current business models have developed based on the expectation that utilities will be sheltered from this source of volatility.¹⁶ For this reason, suddenly moving from a 100 percent passthrough to a zero-percent pass-through policy could undermine a utility's financial stability, driving up its cost of capital and eventually necessitating rate hikes.¹⁷

Fortunately, states do not need to shift 100 percent of the fuel-cost risk back onto the utility. The goal of reforming the FAC is simply to motivate the utility to keep its fuel costs in check—and this can be done while limiting the total risk the utility is exposed to.

This reform can be accomplished by updating the FAC to only pass through part of the fuel costs to customers. This does not mean that customers wouldn't pay anything for the rest—just that they

¹⁵ Jessie Ciulla, Gennelle Wilson, and Rachel Gold, What Utility Regulators Needs to Know about the Inflation Reduction Act: How to Ensure the Biggest Boon to the Energy System in US History Supports Affordable, Reliable Electric Service, RMI, 2022, <https://rmi.org/insight/what-utility-regulators-need-know-about-ira>

¹⁶ The relevant features of current utility business models include but are not limited to their capital structure, organizational structure, and risk profile.

¹⁷ A utility's cost of capital is the minimum amount the utility would need to pay debt and equity investors to secure the funds it needs to run its business. This is sometimes referred to the utility's "true" cost of capital to distinguish it from the estimated cost of capital regulators use when setting rates, which is generally higher than the true cost of capital.

would reimburse the utility for the rest of the fuel in the same way they pay for most utility expenditures. In other words, these costs would be recovered in rates that are set in advance and not trued up afterwards to match actual expenditures. This reform is called “fuel-cost sharing,” though in reality what it does is share the risk that fuel costs will deviate from expectations between the utility and its customers.

Fuel-cost sharing can be implemented in different ways—and we discuss key design options later. However, at this point it would be helpful to understand the basic mechanics of the form that has been most often adopted by states thus far.

This form of fuel-cost sharing requires only a modest departure from the way most FACs are implemented today. Under the typical 100 percent pass-through policy, a forecast of fuel costs is first built into base rates and the FAC then trues up the forecast once the actual expenditure has been made. The FAC does this by charging or crediting customers for the difference between the forecasted and actual fuel costs via a rider; this usually appears as a separate line item on customer bills. The only change to this status-quo policy that is made to implement the reform is to true up less than 100 percent of this difference.

For example, a fuel-cost sharing policy of this type could true up just 90 percent of the gap between the forecasted and actual fuel costs. This would mean that if fuel costs are less than forecast the utility will get to keep 10 percent of the underspend, and if fuel costs exceed the forecast it will bear 10 percent of the excess amount. In other words, the utility will now have a financial incentive to seek ways to reduce fuel costs—and customers will receive 90 percent of any savings.

While this is the variant of fuel-cost sharing that has been most widely adopted to date by the states addressing the FAC, it is not necessarily the optimal one. One of its biggest drawbacks is that if the utility is able to inflate the fuel-cost forecast that is built into base rates, it will be able to retain a share of that inflated amount (e.g., 10 percent in our example). In other words, anchoring the fuel-cost sharing mechanism to a forecast can invite the utility to game the forecast.

Fortunately, there are ways to avoid this problem, and there are also alternative structures that can allow regulators to tailor their fuel-cost sharing policy to local circumstances. We will discuss some of these policy design options later.

Avenues for Reform

It is one thing to identify a needed reform—and a different thing entirely to make it happen. The most fruitful strategy will vary by state, and it may also vary by utility.

To identify appropriate reforms, it is important to first understand how fuel costs are currently regulated. The biggest question is whether 100 percent of fuel costs are passed through to customers or if there is some form of fuel-cost sharing already in place. Keep in mind that 100 percent fuel-pass-through mechanisms are sometimes called different names, even though we refer to them all as FACs here.

The next step is to determine which decision makers have the ability to reform the existing policy. Public utility commissions are responsible for overseeing regulated utilities and setting the prices

they can charge, so achieving FAC reform will likely require engaging with the commission. However, some state legislatures have passed laws that mandate 100 percent pass-through policies, so, in these states, reform will require revising these statutes. In addition, interested legislatures can motivate reform at the commission by encouraging or requiring it to revisit these policies.

How to Engage a Public Utility Commission on Fuel Adjustment Clause Reform

To engage a public utility commission on the topic of FAC reform, advocates first need to identify the best formal venue.

Commissions make decisions through individual proceedings (aka “dockets”) that focus on particular regulatory issues. Each proceeding is assigned a specific identifying number (often called a “docket number”), and the documents associated with the proceeding can generally be obtained through a commission’s online docket search.¹⁸ Participating in a proceeding typically requires applying for intervenor status, but sometimes the commission will issue a notice inviting comments from the general public.¹⁹ The types of proceedings that may be good venues for FAC reform include the following:

Dedicated FAC dockets. Commissions typically periodically review and approve fuel costs for recovery in specific FAC-related dockets, so engaging in these proceedings can be one way to push for changes. However, in some states, these proceedings offer little opportunity to scrutinize utility requests for fuel-cost recovery—for example, where stakeholders lack access to key data, face rapid turn-around times for comment submission, are constrained by a narrow definition of the issues in scope for the proceeding, or face other barriers that prevent them from advocating effectively for reform. In these cases, pushing for changes to the way the commission conducts these dockets may be a prerequisite to reforming a FAC through them.

Rate cases. General rate cases may also provide a venue for stakeholders to raise concerns about fuel-cost treatment and offer solutions. The basic function of rate cases is to set the utility’s base rates going forward, and to do this the commission examines a wide array of different topics that pertain to utility expenditures. Rate cases are typically conducted over a longer time frame than dedicated FAC dockets and in a way that invites more input from stakeholders.

“It is one thing to identify a needed reform—and a different thing entirely to make it happen. The most fruitful strategy will vary by state, and it may also vary by utility.”

¹⁸ The structure of online docket searches varies greatly—some are relatively intuitive while others can be very difficult to navigate. If you have trouble with the docket search (or more general questions about what to look for), commission staff are often willing assist if asked.

¹⁹ To become an intervenor, a party must typically submit a request to the commission that justifies why they should be granted intervenor status. Generally, this means showing that they have a compelling interest in the outcome and that they will make some kind of unique/valuable contribution because they represent a particular group/perspective. The commission will then either grant or deny them intervenor status.

Performance-based regulation proceedings. Proceedings that focus on investigating or implementing performance-based regulation (PBR) are another potential venue for FAC reform. The purpose of fuel-cost sharing is to better align the utility's incentives with the interests of customers and society, which is precisely the definition of PBR. In other words, fuel-cost sharing can be considered a PBR mechanism, and it is therefore appropriate to discuss in PBR proceedings.

Special dockets. Commission rules vary on the authorized scope and process for dockets on special topics. However, in nearly every state, a commission could open a special docket to review current fuel-cost recovery policies, consider the implications of updating these policies, and solicit public input. In some cases, a legislative hearing can spur a commission to open a special docket, and in other cases customers or other stakeholders can petition it to do so.

Public utility commissions vary greatly across states. Some may quickly recognize the problems created by 100 percent pass-through policies and act decisively to change them. In many cases, this type of response is driven by a particularly proactive commission member, so it is worthwhile for advocates to consider which commissioners may be inclined to act as champions for reform. Other commissions may not be receptive to the idea of addressing FAC reform without outside pressure.

How to Enlist Other Actors to Encourage a Commission to Act

Where a public utility commission is not inclined to take up the issue of FAC reform or is prohibited from doing so, advocates should consider enlisting the help of other parties. These include the following:

State Legislators. Though setting utility rates is the commission's responsibility, state legislators may be able to direct or encourage the commission to take action. For example, lawmakers could hold a hearing on the FAC, introduce legislation directing the commission to align its mission and operations with state policy goals, distribute sign-on letters for colleagues to join them in encouraging commission attention to fuel-cost pass-through policies, or hold stakeholder meetings on the topic.

Governors. Governors may also be able to encourage FAC updates. For example, a governor may be able to issue an executive order requiring the commission to consider or recommend reforms that align its activities with affordability or climate goals, or one that provides guidance about key design criteria (e.g., what constitutes "the public interest" for the purpose of regulatory decision-making). Also, in many states the governor is responsible for appointing commission members. In these cases, the governor could prioritize FAC reform as a significant consumer protection agenda item when appointing (or reappointing) individuals to serve on the commission.

Attorneys general. In some states, the attorney general can petition the public utility commission to open a proceeding to consider a particular issue—which could include FAC reform. Also, in most states, an attorney general can initiate a review of confidential information in fuel-supply agreements to determine whether alleged trade secret information

meets the legal standard for being withheld from public view. Such a review could examine key contract terms, such as guaranteed delivery volumes regardless of need, as well as cost or price escalators that are above consumer price index averages. Some attorneys general also serve as the consumer advocate, which may give them the power to request commission dockets and take other actions to support FAC reform.

“Exactly which steps will be needed might not be clear at the outset, and advocates should be prepared to adapt their strategy if they encounter twists and turns on what they had imagined would be a straight path. However, to be successful the most important thing is to get started.”

Utilities. Since the idea of FAC reform is to expose utilities to a share of the fuel-cost risk, they may not be in favor of updating the policy. However, in some cases a utility may be receptive to the idea if it expects to be able to profit by reducing fuel costs. Utility proposals often carry substantial weight with both public utility commissions and legislators, so utility support of reform can help move the process forward.

Though the recommendations discussed are broadly applicable, every public utility commission is unique. FAC reform advocates can tailor their approach to their particular commission by researching its processes, mission, and relevant recent decisions, as well as the attitudes and policy positions its members demonstrate through their statements and actions.

How to Achieve Reform Through Legislative Action

In all states, a public utility commission can only operate within the constraints of state statutes, which are established by state legislatures.

In some states, the legislature has enshrined the FAC into statute. In these states, the public utility commission alone will not be able to update the policy since the legislature must first amend the statute. Where this is the case, would-be changemakers should develop a legislative strategy prior to—or at least in parallel with—their efforts to engage the commission.

In other states, the legislature has provided the public utility commission with the statutory authority necessary to revise the fuel-cost pass-through policy. In these states, advocates may wish to focus their efforts solely on the commission. However, even in these states, a legislative route to change is possible. For example, state lawmakers could introduce legislation to reform the FAC, even if the existing policy was implemented by the commission.

When drafting a bill, state legislators often meet with other lawmakers and affected parties to inform policy design and secure buy-in. Advocates should be aware that this may occur, and they may even wish to encourage their legislative champions to meet with utility representatives, consumer

advocates, and other stakeholders. These parties may be more open to policy reforms when consulted early and away from the media attention that can occur once a bill is introduced or a hearing is in progress, and meeting with them may also result in better policies. However, utilities or other stakeholders may also use this opportunity to urge lawmakers to weaken or abandon the proposed reforms. To guard against this possibility, advocates can educate their legislative champions ahead of time about the arguments against reform that they are likely to hear and whether those arguments are reasonable.

Depending on the state's policies governing communication between lawmakers and commissioners, legislators may also wish to engage commissioners directly in crafting statutory reforms to fuel-cost pass-through policies. Some commissioners may choose to be deeply involved in such discussions, and they may even be willing to endorse specific legislative changes or testify at public hearings. Other commissioners may be reluctant to step outside of their quasi-judicial role in this way, even if they agree that a legislative update would be beneficial.

Advocates interested in legislative reform can increase the chances for success by providing their legislative champions with specific policy recommendations and examples to follow. In particular, advocates would be wise to point to precedents for FAC reform from other states, as lawmakers may be reluctant to act if they believe they will be the first state to implement such a change.²⁰

How to Get Started on Reforms in Your State

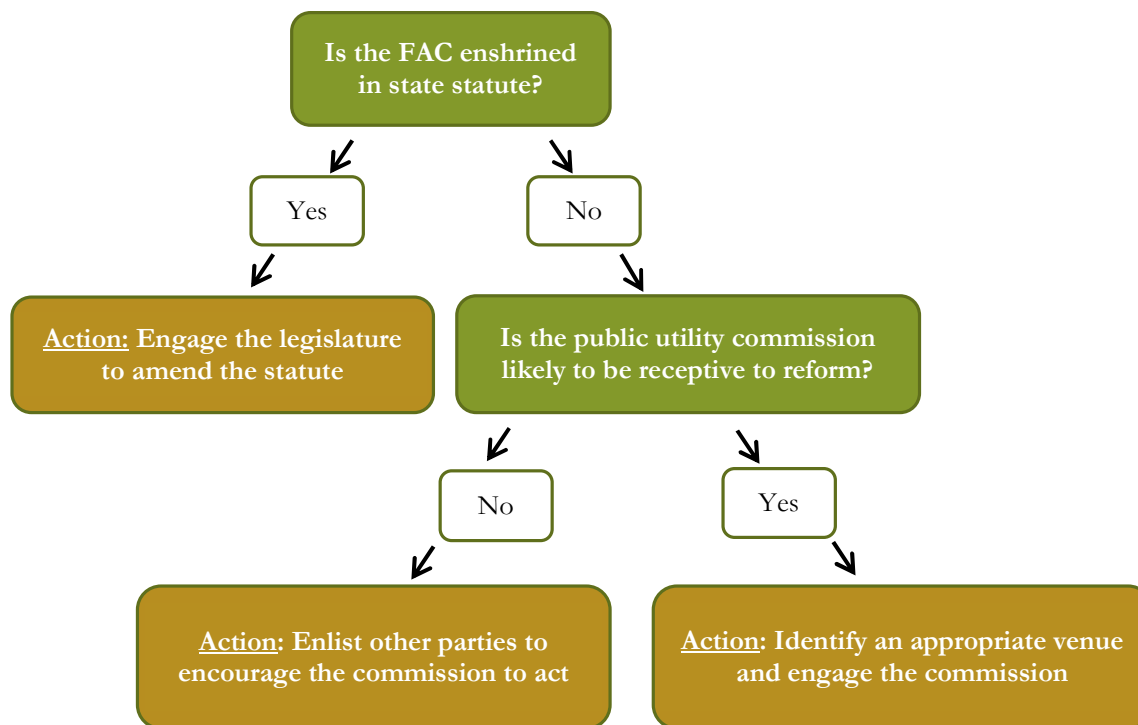
Achieving fuel-cost pass-through reform in a state may be a complex process, as advocates may need to intervene in arcane regulatory proceedings, navigate legislative policymaking, and/or enlist the support of other parties. The process may be relatively quick, but it could also take years to update a FAC policy.

Exactly which steps will be needed might not be clear at the outset, and advocates should be prepared to adapt their strategy if they encounter twists and turns on what they had imagined would be a straight path. However, to be successful, the most important thing is to get started.

Once advocates have decided they want to reform the policy in their state, they are ready to start crafting a strategy. Figure 5 illustrates the key questions that advocates embarking on this process will face.

²⁰ We provide some examples of states that have implemented FAC reforms later in this primer, and national nonpartisan organizations like the National Conference of State Legislators may be able to provide additional information.

Figure 5. Key Steps for Achieving Fuel Adjustment Clause Reform



Key Policy Considerations

Though the concept of fuel-cost sharing is simple, this reform can be implemented in a variety of ways. In addition, there are other reforms that could also help address related problems. When considering ways to reform an existing FAC, the following topics are worthy of consideration.

Amount of Fuel-Cost Sharing

When designing a fuel-cost sharing policy, advocates should consider the degree of sharing between the utility and its customers. For example, a utility could be responsible for just 5 percent of fuel costs (i.e., passing through 95 percent to customers) or for 20 percent (i.e., passing through 80 percent to customers). The ideal sharing percentage is a level that is high enough to motivate the utility to keep its fuel costs in check, but low enough that the utility is not exposed to unreasonable levels of risk.²¹

There is not one “best” sharing amount that should be applied to all utilities because utilities vary in multiple ways. For example, utilities rely on different mixes of fuel- and non-fuel generation sources, and they face different risk profiles in their jurisdictions.

²¹ If the utility is exposed to a level of risk that is excessive, it could make it harder for the company to access low-cost capital. This could drive up its cost of capital (and by extension, the rates it must charge customers to remain financially whole), and at the extreme it could even create cash-flow problems severe enough to prevent it from serving its customers. While moderate sharing percentage would be unlikely to cause such problems, there may be an upper limit to how much sharing is in customers’ best interest.

Symmetry

Another design question is whether a fuel-cost sharing mechanism should be symmetrical or asymmetrical. A symmetrical mechanism shares the same percentage regardless of whether the actual fuel costs are higher or lower than expected. An asymmetrical mechanism shares a different amount in each case. Both symmetrical and asymmetrical sharing can be structured to provide both rewards and penalties.

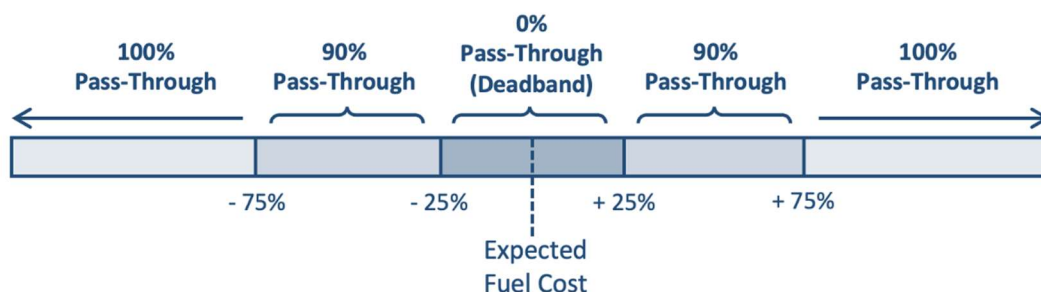
For example, a commission may design a mechanism with a higher pass-through percentage when fuel costs are lower than expected (thus passing more of the savings on to customers) than when fuel costs are higher than expected. Such a mechanism can direct more of the benefits of fuel-cost savings to customers—but it also weakens the utility’s incentive to pursue opportunities to reduce fuel costs below a certain level. Symmetrical mechanisms also tend to be easier for customers to understand than asymmetrical mechanisms. These tradeoffs should be carefully considered when deciding between symmetrical and asymmetrical designs.

Straight Sharing Versus Sharing Bands

The simplest structure for a fuel-cost sharing mechanism is to always require the same level of utility fuel cost responsibility (e.g., 10 percent) regardless of how much the utility’s actual costs deviate from expectations. This approach, which is sometimes call “straight sharing,” is the most common among existing fuel-cost sharing policies.

Another option is to use bands (also sometimes called thresholds). For example, a regulator could adopt a mechanism that performs no true-up if actual fuel costs fall within 25 percent of the expected value (this is called a “deadband”), a 90 percent true-up if actual costs are 25-75 percent greater than or less than that value, and a 100 percent true-up if they deviate by more than 75 percent. Figure 6 illustrates this hypothetical banded design.

Figure 6. Example of a Policy Design with Sharing Bands



In this example, the pass-through amount increases as the size of the deviation from the expected fuel cost becomes larger. Such a design can reduce the risk to the utility posed by large fuel-cost spikes, as well as the risk to customers of paying for large windfall profits if fuel costs dip very low. Alternatively, sharing bands could be used to increase (rather than decrease) the utility’s risk exposure as fuel costs deviate more from the expected level; this could greatly increase the utility’s incentive to reduce its reliance on fuel. Sharing bands could also be deployed in an asymmetrical fashion.

While banded designs can reduce the risk of extreme outcomes to the utility or its customers, they can also create uneven incentives. For example, a banded design that passes through 100 percent of fuel costs beyond a certain threshold dissolves the utility's financial incentive to reduce costs beyond that threshold. In addition, banded designs can be harder for customers to understand and more complex to administer than straight sharing.

Forecast Versus Historical Prices

Fuel-cost sharing mechanisms in place today share the difference between the actual fuel costs a utility incurs and the costs it was expected to incur. These “expected” costs can be based on either a forecast (i.e., a forward-looking estimate) or historical values. Forecasts are the most common approach used today, but that does not necessarily mean they are the best choice.

Traditional 100 percent pass-through policies typically utilize forecasts to set the base rates that the FAC then trues up, and most states that have adopted fuel-cost sharing have continued to rely on them. Forecasts may also be preferred because they can be tailored to reflect changing conditions—but, in reality, the accuracy of fuel-cost forecasts may be low. This is particularly true for forecasted natural gas costs, as this fuel is subject to substantial price volatility that is hard to predict.^{22, 23}

However, forecasts have another drawback in the context of fuel-cost sharing: they open the door to possible gaming. Specifically, if the utility is able to inflate the forecast, it will be rewarded with a greater amount of “savings” relative to it (and also be less likely to have to bear a share of any “overspends”). It is important to note that any such gaming will not reduce the utility's financial incentive to seek savings once the forecast is adopted—so the fuel-cost sharing mechanism will still encourage the utility to reduce fuel costs. However, if the utility manages to game the forecast this will increase the costs of the policy to customers.²⁴

The alternative is to use historical spending to set the expected fuel-cost baseline. Relying on historical actuals rather than forecasts avoids the gaming problem just described, and it is also more straightforward to calculate.

²² The price volatility of natural gas is driven by multiple factors. These include domestic transportation and storage constraints, shifting levels of international demand, and global supply-chain disruptions (e.g., due to extreme weather events and geopolitical events).

²³ For example, the price forecasts shown on pg. 11 of the following report are typical: Deloitte, Energy, oil, and gas price forecast: Energy costs are stretching price elasticity and energy affordability, December 31, 2022. <https://www2.deloitte.com/ca/en/pages/resource-evaluation-and-advisory/topics/deloitte-canadian-price-forecast.html>

²⁴ The company will have the same financial incentive to reduce fuel costs because the utility's marginal incentive (i.e., the reward it can earn for reducing fuel costs by the next increment) is not changed by the level of the forecast. For example, imagine a utility that is subject to a 90 percent pass-through policy and that is expected to use 100 units of fuel at \$5/unit. If this utility can find a way to spend \$4/unit on fuel instead of \$5/unit, it will earn a \$10 reward for doing so (i.e., 100 units x \$1/unit * 10 percent). If these are real savings that would not have occurred without the utility's effort, everyone wins: the utility gets its \$10 reward and customers receive \$90 of savings. However, if the utility can convince its regulator that the price of fuel is likely to be \$6/unit instead of \$5/unit, it will earn a \$10 reward for doing nothing (i.e., for spending \$5/unit) and then another \$10 for reducing its spending to \$4/unit. Either way, the utility earns the same incentive (\$10) for reducing its fuel costs from \$5/unit to \$4/unit, so its marginal incentive to pursue this savings opportunity is the same. However, if the utility is able to inflate its forecast to \$6/unit, its customers will pay an extra \$10 incentive and receive nothing in return.

However, relying on historical spending could itself create an incentive problem under certain policy designs. When the utility's historical spending is used to set the baseline, reducing fuel costs in one year will reduce the expected-cost baseline in future years. This means that if the utility's reward for reducing fuel costs now is not large enough to offset the burden of operating under a lower baseline in the future, the utility will not be motivated to reduce its fuel costs. This situation is most likely to occur where an asymmetrical design is used that requires a utility to bear most of the cost when actual fuel prices are higher than expected, but which passes on most of the savings to customers when they are lower than expected.

Transparency

In many states today, the moral hazard problem created by FACs is compounded by a lack of visibility into fuel-supply contracts. While commission staff often have access to otherwise undisclosed contracts and key terms, they may not have the time or expertise to complete a thorough review on their own. When advocates and other stakeholders are barred from accessing key documents, they cannot identify potential prudence issues and flag them for the commission and its staff to consider. The end result is less regulatory scrutiny of utility fuel expenditures.

Though fuel-cost sharing addresses the moral hazard problem created by traditional 100 percent pass-through policies, transparency is still important. State lawmakers and utility regulatory commissions can take steps to ensure that the key terms of utility fuel-supply contracts are transparent to customers and other stakeholders, while protecting necessary trade secrets as appropriate. Such terms include (but are not limited to) pricing, annual escalators or other pre-determined price increases, minimum delivery amounts, and contract length.

Disallowance on Prudence Grounds

The purpose of fuel-cost sharing is to motivate the utility to seek ways to reduce its fuel costs. However, it is not the only policy tool available to accomplish this objective. Another option is to identify fuel-cost savings opportunities that are available to the utility and to disallow cost recovery if the utility fails to take advantage of these opportunities.

For example, a regulator might determine that a certain utility could reduce its reliance on natural gas for power generation by 5 percent a year if it aggressively pursues a demand-side portfolio of energy efficiency, demand response, and load-shifting measures. The regulator could then allow the utility to pass through all natural gas costs up to this level via the existing FAC, while disallowing any recovery of costs beyond this level on the grounds that they were imprudently incurred.²⁵

As another example, a regulator could demonstrate a willingness to scrutinize all fuel costs presented for recovery and disallow any for which the utility cannot convincingly demonstrate prudence. This more rigorous prudence review could encourage the utility to pursue opportunities to reduce fuel costs, to be more transparent as a strategy to show the regulator that it has been making an effort, and to reduce its reliance on fuel-fired generation over time. For this strategy to be effective, however, it must be clear to the utility that disallowance is a real and substantive risk—simply

²⁵ The allowed level of natural gas usage could also be adjusted to reflect actual weather conditions. Such a normalization could reduce the risk of windfall losses or gains due to usage fluctuations driven by weather events, which are not under the control of the utility.

applying a slightly higher level of review to an existing FAC docket that currently functions as a rubber stamp is unlikely to be effective.

Hedging

Fuel-cost sharing can reduce the risk posed by fuel-price spikes by encouraging the utility to secure more favorable fuel-supply contracts and reduce its reliance on fuel-based generation sources. However, another way to reduce the risk of price volatility is hedging. Hedging refers to the use of financial instruments to mitigate the risk of unexpected negative investment outcomes. Requiring that utilities hedge can reduce the risk of fuel-price spikes to customers, but hedging also means incurring an additional cost that is then passed on to customers. Whether to encourage or require hedging (or particular kinds of hedging) is a question that should be considered whether or not fuel-cost sharing is in place.

Purchased Power

Fuel-cost sharing is only relevant for vertically integrated utilities that purchase fuel to generate power and then sell that power to customers. However, some regulated utilities do not own generation (these “wires only” utilities are the norm in restructured states), and even vertically integrated utilities may buy substantial amounts of power from other parties to serve their customers. These parties may include independent power producers, other regulated utilities, and unregulated affiliate companies of the purchasing utility.

Typically, the cost of purchased power is recouped in the same fashion that fuel costs are: as a 100 percent pass-through to customers. A sharing mechanism can be implemented for purchased power in the same way as for fuel costs, but whether this makes sense will depend on local circumstances.

In cases where a regulator is implementing fuel-cost sharing for a vertically integrated utility, applying an equivalent sharing policy to purchased power should be seriously considered—because without this, gaming may occur. For example, during a natural-gas price spike a utility that is subject to fuel-cost sharing but not purchased-power cost sharing could substitute spot-market purchases for its own generation. Such a move would likely raise rather than lower costs to customers, contrary to the goal of the fuel-cost sharing policy. Applying sharing to both fuel and purchased power could avoid this type of behavior.²⁶

However, in cases where the utility does not own generation, the case for applying a sharing policy to purchased power is less clear. For a utility that has substantive opportunities to lower these costs through its own actions, a purchased-power sharing policy could make sense. For instance, a wires-only utility may be able to lower the cost of the power it purchases by aggressively promoting energy efficiency programs to its customers. It could also lower costs by negotiating better contracts, switching to different suppliers, or helping customers shift demand to lower-cost hours (e.g., via demand-response programs, managed EV charging, and time-varying rates). However, if a wires-only utility has limited control over purchased-power prices (e.g., because it purchases most of its power through wholesale markets where it acts as a price-taker rather than as a price-setter) and

²⁶ If a purchased-power sharing policy is adopted alongside a fuel-cost sharing policy, they should be equivalent—but this does not mean identical. Since fuel costs only make up a portion of purchased-power costs, the sharing factor for purchased power could be lower than the one applied to the utility’s own fuel costs.

limited ability to influence customer behavior (e.g., because a separate state entity is responsible for administering demand-side management programs), it may make little sense to apply a sharing mechanism to its purchased power costs.

Stakeholders should also note that purchased power includes electricity generated from both fuel- and non-fuel resources. This means that purchased-power cost sharing will not necessarily drive decarbonization in the same way as fuel-cost sharing would be expected to. Where reducing carbon emissions is an important policy goal, additional strategies to accomplish this aim could be considered. For example, the sharing mechanism could be designed in a way that distinguishes between different types of generation resources (e.g., it could apply a higher pass-through percentage to renewables than to fossil fuel-fired generation).

Examples of State Fuel-Cost Sharing Policies

A few states have adopted fuel-cost sharing mechanisms to varying degrees, and interest in this neglected aspect of utility regulation has been growing in recent years. However, advocates should keep in mind that just because a particular design feature is common does not necessarily mean it is a good idea. Being familiar with existing forms of fuel-cost sharing policies but also willing to advocate for improvements to them is likely to result in the best outcome. States that have implemented fuel-cost sharing include Hawaii, Idaho, Oregon, Wyoming, Montana, Washington, Wisconsin, Vermont, and others. Below we discuss how a few of those states have adopted such policies.

Hawaii

The Hawaii Public Utilities Commission adopted fuel-cost sharing for the Hawaiian Electric Companies (HECO) in 2018.²⁷ The Energy Cost Recovery Clause (ECRC) utilizes a straight-sharing approach anchored to a forecast of fuel costs, in which the utility passes through 98 percent of fuel costs to customers regardless of whether its actual costs are above or below the forecast. HECO's annual financial exposure under the policy is capped at \$2.5 million. In 2022, the Commission invited intervenors to consider proposals to modify the risk sharing component of the ECRC, signaling an openness to increase the sharing factor—though no decision to adjust it has yet been made.²⁸

Idaho

The Idaho Public Utilities Commission adopted the Power Cost Adjustment (PCA) mechanism for Idaho Power in 1992 to share power supply costs between the utility and its customers. The mechanism features a straight sharing design, relies on forecasts, is symmetrical, and includes purchased power. The PCA initially passed through 90 percent of power supply costs, but in 2009 the commission increased this to 95 percent. In approving this change, it explained that “power supply cost volatility has increased significantly since the PCA was implemented, and that with increased volatility, a sharing percentage of 5% still provides strong incentive for the Company to

²⁷ Hawaii Public Utilities Commission, Final Decision and Order No. 35545, Docket No. 2016-0328, June 22, 2018, <https://puc.hawaii.gov/wp-content/uploads/2018/06/DO-No.-35545.pdf>

²⁸ Hawaii Public Utilities Commission, Decision and Order No. 38429, Docket No. 2018-0088, June 17, 2022, pg. 56.

make prudent power purchases.”²⁹ In 2009, the commission also adopted a mechanism called the Energy Cost Adjustment Mechanism (ECAM) for Rocky Mountain Power. The ECAM features straight sharing with a 95 percent pass-through, has a symmetrical design, employs forecasts, and includes purchased power.³⁰

Wyoming

In 2011, the Wyoming Public Service Commission adopted the Energy Cost Adjustment Mechanism (ECAM) for Rocky Mountain Power. The ECAM was a modification of a prior sharing policy called the Power Cost Adjustment Mechanism (PCAM), which was created based on a statute that allowed the commission to use non-traditional rate tools to optimize outcomes.³¹ The ECAM trues up the utility’s actual net power costs (which include fuel, purchased power, and certain other costs) to its forecasted costs in a symmetrical fashion. The ECAM previously featured a 70 percent pass-through and it employs an 80 percent pass-through today.³²

Missouri

In 2005, the Missouri legislature enacted Senate Bill 179, which was subsequently codified as Section 386.266 of the Revised Missouri Statutes (RSMo). The legislation authorized the utilities to pass fuel and purchased power costs through to customers if approved by the Missouri Public Service Commission, and it also granted authority to the commission to include an incentive for efficiency and cost-effectiveness as part of the mechanism. The commission implemented the first mechanism in 2007 (and the last one in 2015). In Missouri, these mechanisms are referred to as “fuel adjustment clauses” (FACs) even if they feature fuel-cost sharing.³³ The mechanisms in place for Ameren, Evergy, and Liberty Utilities all feature straight sharing with a 95 percent pass-through.³⁴

Wisconsin

The Wisconsin Public Service Commission was authorized by Wisconsin Statute § 196.20(4) to establish automatic adjustment clauses for regulated utilities, and the commission codified the rules

²⁹ Idaho Public Utilities Commission, Order No. 30715, Case No. IPPC-E-08-19, January 9, 2009, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE0819/OrdNote/20090109final_order_no_30715.pdf

³⁰ Idaho Public Utilities Commission, Order No. 30904, Case No. PAC-E-08-08, September 29, 2009, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE0808/OrdNote/20090929final_order_no_30904.pdf; Idaho Public Utilities Commission, Order No. 35419, Case No. PAC-E-22-05, May 26, 2022, https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE2205/OrdNote/20220526Final_Order_No_35419.pdf

³¹ Wyoming Public Service Commission, Memorandum Opinion, Findings, and Order, Docket No. 20000-368-EA-10, February 4, 2011, <https://pscdocs.utah.gov/electric/09docs/0903515/71051ExhibitA2-9-11.pdf>

³² For the present 80 percent pass-through policy, see the current version of Sheet No 95-6 (P.S.C. Wyoming No. 17, Original Sheet No. 95-6). For the previous 70 percent pass-through policy, see P.S.C. Wyoming No. 16, First Revision of Amended Original Sheet No. 95-6 Canceling Amended Original Sheet No. 95-6. Source: Rocky Mountain Power, Energy Cost Adjustment Mechanism, Schedule 95. The current tariff can be downloaded at: https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/095_Energy_Cost_Adjustment_Mechanism.pdf

³³ This is different from how we use this term in this primer, where we define a FAC as a 100 percent fuel-cost pass-through mechanism.

³⁴ Lena M. Mantle, Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper; Office of the Public Counsel, Revised January 14, 2022, <https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=939661980>

for doing so as Wisconsin Administrative Code § PSC 116.03.^{35,36} Under these rules, each of the state's five major investor owned electric utilities (Wisconsin Electric Power Company, Wisconsin Public Service Corporation, Madison Gas & Electric, Wisconsin Power and Light, and Northern States Power – Wisconsin) are required to file fuel cost plans.³⁷ Each plan includes a forecast of the utility's expected costs for fuel, purchased power, and related expenditure categories to be collected from customers. Once the utility's actual fuel (and related) costs are known, the commission can approve a true-up to collect or refund any difference that represents 2 percent of the forecasted amount. In other words, there is a 2 percent deadband where no sharing occurs and a 100 percent pass-through outside this deadband. The commission has the authority to rule on whether or not the utility's actions were prudent when determining the extent of cost recovery to be allowed. The true-up occurs through a fuel adjustment which appears on customers' bills.³⁸

Conclusion

Many Americans today struggle to pay their electric bills. Fuel costs often represent a large share of customer bills, and unlike most rate components these charges can vary substantially from month to month. Reducing fuel costs—as well as fuel-cost volatility—is imperative to ensuring that electricity is affordable and accessible to all.

Fortunately, electric utilities have more ways to reduce fuel costs today than ever before. These opportunities exist on both the supply and demand side (e.g., increasingly cheap solar and wind generation, distributed energy resources that shift load to lower-cost hours), and they are enhanced by supportive federal policies like the Inflation Reduction Act (IRA). However, these opportunities have not spurred a utility rush to decrease fuel costs. Why?

The answer is that most states pass 100 percent of fuel costs through to customers, which gives utilities no financial incentive to reduce these costs. If a utility finds any savings, customers reap all the benefits—and if it spends more than necessary, customers pick up the bill.

It is time for these outdated policies to change, and advocates can play important roles in this process. This primer has described the problems created by existing 100 percent pass-through policies, explained how fuel-cost sharing reforms can produce better outcomes, and provided tools that advocates can leverage to encourage reforms in their states. If these reforms are well designed, they will result in lasting benefits for customers, utilities, and the environment.

³⁵ Wisconsin Statutes, <https://docs.legis.wisconsin.gov/statutes/statutes/196/20>

³⁶ Wisconsin Public Service Commission, Chapter PSC 116, March 15, 2023, https://docs.legis.wisconsin.gov/code/admin_code/psc/116.pdf

³⁷ Wisconsin Public Service Commission, Final Decision, Docket 6680-ER-103, December 13, 2022,

³⁸ Alliant Energy, RE: Wisconsin Power and Light Company Electric Tariff for Fuel Adjustment, Docket No. 6680-ER-103, December 21, 2022, <https://apps.psc.wi.gov/pages/viewdoc.htm?docid=455114>

STATE OF GEORGIA
BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:	)	
	)	
Georgia Power Company's	)	Docket No. 56765
Fuel Cost Recovery (FCR-27)	)	

EXHIBIT AL-3

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In Re: Georgia Power Company's	)	
2023 Fuel Cost Recovery (FCR)	)	Docket No. 44902
Application	)	

DIRECT TESTIMONY

OF

BRENT ALDERFER

**ON BEHALF OF SIERRA CLUB AND SOUTHERN ALLIANCE FOR CLEAN ENERGY
("SACE")**

April 14, 2023

1 **Q: PLEASE STATE YOUR NAME, POSITION, AND ADDRESS.**

2 **A:** My name is Brent Alderfer. I am a former public service Commissioner, an energy project
3 developer and policy advisor. My address is Meetinghouse Rd, New Hope, Pennsylvania.

4 **Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

5 **A:** Sierra Club and Southern Alliance for Clean Energy (“SACE”).

6 **Q: PLEASE DISCUSS YOUR RELEVANT EXPERIENCE, PROFESSIONAL EXPERTISE,**
7 **AND EDUCATIONAL BACKGROUND.**

8 **A:** I have a law degree from Georgetown University and an electrical engineering degree from
9 Northeastern University.

10 I am cofounder and CEO of a company that developed utility-scale solar generation starting in
11 2010. We developed several gigawatts of utility-scale solar early in the commercialization of solar for
12 utilities across the country, bringing the price down to compete in competitive bidding with other
13 technologies. We developed the Butler Solar project here in Georgia, which was selected by Georgia Power
14 through a competitive bid process and included in its 2015 energy portfolio. The project was purchased in
15 2015 by Southern Power, a subsidiary of Southern Company. By 2021 we had developed several gigawatts
16 of solar projects and built a pipeline of about 10 gigawatts of solar projects under development. At the end
17 of 2021 we sold the solar development company to AES Corporation, a global diversified energy company
18 rapidly expanding renewable energy assets. I have no financial interest in AES or in solar project
19 development.

20 In the decade prior to 2010 we developed utility-scale wind farms. We originated early wind
21 projects with utility green pricing programs in partnership with 15 different utilities as the economics of
22 wind generation in moderate wind regimes improved. As the economics of wind technology continued to
23 improve at scale, we developed larger wind projects and by 2005 had originated about two gigawatts of
24 projects. We sold the wind development company in 2006 to Iberdrola, a Spanish utility and largest owner
25 of renewable energy at the time. I worked for Iberdrola for several years as they entered the U.S. market
26 and built out the pipeline of wind projects in the U.S. They now own eight utilities in the U.S. serving about

1 3 million customers under the name Avangrid. I have no financial interest in Iberdrola, Avangrid or wind
2 development. Prior to wind and solar development, I was a utility Commissioner on the Colorado Public
3 Utility Commission. Prior to that I practiced law in corporate and commercial practice in Denver and
4 Philadelphia. I have attached a copy of my CV to my testimony (BA-Exhibit 1).

5 **Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?**

6 **A:** No.

7 **Q: WHAT IS THE FOCUS OF YOUR CURRENT WORK?**

8 **A:** Currently, I am working and advising on projects delivering favorable economics in the transition
9 to reliable, clean energy portfolios. I serve on the board of New Energy Economics, a 501(c)(3) organization
10 offering non-partisan data-driven analysis on energy policy options that result in clean-energy paths to
11 lower utility rates, maintain reliability, and foster economic development for communities and states.

12 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

13 **A:** In my testimony, I provide the following:

- 14 • A review of the drivers of Georgia Power's proposed fuel cost increase, including
15 increasing fuel prices, greater fuel price volatility, and increased reliance on natural gas
16 generation in Georgia Power's portfolio;
- 17 • Forward planning assumptions based on rising fuel prices and fuel price volatility
18 and their impact on rates and on Georgia Power's ability to make prudent necessary
19 investments in the future;
- 20 • Tools for the Commission to mitigate and hedge fuel-cost risks;
- 21 • A summary of the shared economics of adding renewable generation including
22 additional solar generation to the utility portfolio;
- 23 • Considerations in applying the "just and reasonable" statutory standard to the
24 sudden and extreme fuel-cost increases underlying this and future fuel cases.

25 **Q: WHAT DOCUMENTS DID YOU REVIEW IN PREPARING THIS TESTIMONY?**

26 **A:** I reviewed:

1 (i) The direct testimony of Sarah P. Adams and Adam D. Houston on behalf of Georgia Power
2 Company, and

3 (ii) Section 46-2-26 of the Georgia Code: Restriction as to Utilization of Fuel-Adjustment Tariffs;
4 Procedure for Rate Change by Utility Based Solely on Change in Fuel Costs; Extent of Commission's Power
5 Over Rate Changes; Disclosure Requirements for Utilities Seeking Rate Change

6 **Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS IN THIS CASE.**

7 · Planning assumptions going forward need to assume, prepare for and reduce
8 exposure to higher and more volatile natural gas prices;

9 · High concentrations of natural gas generation in the portfolio multiply the rate
10 shock from increases and swings in fuel prices;

11 · Renewable generation as a fuel-free resource lowers electricity costs and provides
12 an effective long-term hedge against high and volatile fuel prices;

13 · Economics of utility-scale solar allow fuel savings to utility customers on the order
14 of the fuel cost shocks at issue in this case, while at the same time offering investment
15 earning potential for the utility;

16 · Rapid and irreversible structural changes in and exposure to global markets require
17 an update of low fuel-price assumptions and resulting resource decisions as a fundamental
18 underlying element of just and reasonable allocation of fuel costs.

19 **Q: IN GEORGIA, HOW ARE UTILITY FUEL COSTS INCLUDED IN CUSTOMER**
20 **UTILITY BILLS?**

21 **A:** As part of the “Jurisdiction, Powers and Duties Generally” of the Public Service Commission, the
22 Georgia Code provides a procedure for the utility to change customer rates “based solely on change in fuel
23 costs”. O.C.G.A. 46-2-26. The statute requires Commission review under a just and reasonable standard
24 with the burden of proof on the utility to show that an “increased rate, based on fluctuations in fuel costs,
25 is just and reasonable” O.C.G.A. § 46-2-26(d).

1 **Q: IS THIS A COMMON WAY FOR COMMISSIONS TO APPROVE FUEL COST**
2 **RECOVERY?**

3 **A:** Yes, since the late 1970s when swings in fuel prices tied to global oil embargos and global oil
4 demand first appeared many states adopted fuel cost recovery mechanisms to “pass through” fuel price
5 increases directly to customers outside of full utility rate cases that otherwise establish just and reasonable
6 customer rates and utility earnings. Georgia Power recently completed a rate case with new rates taking
7 effect January 1st of this year. This fuel cost recovery case filed so closely upon the recent rate case
8 illustrates the separation of fuel costs from other elements of utility cost of service and the direct impact of
9 fuel costs on customer utility bills.

10 **Q: IN GEORGIA POWER’S STATEMENT ON THE PROPOSED FUEL COST INCREASE,**
11 **THE COMPANY EMPHASIZED THAT IT DOES NOT EARN A PROFIT ON THE FUEL COSTS.**
12 **HOW SHOULD THAT AFFECT THE COMMISSION’S CONSIDERATION IN THIS**
13 **PROCEEDING?**

14 **A:** The utility earns a profit from investments in fuel-burning generation but does not earn
15 profits on fuel purchased for that generation. No party in this case profits from higher fuel costs. The issue
16 of course is who bears the losses.

17 There have been objections over the years from consumer advocates and others to one-hundred
18 percent allocation of fuel risk to customers on grounds of fairness and one-sided risk. Separation of control
19 and risk removes incentives to control fuel costs and mitigate fuel risks. As long as fuel prices stay low, the
20 risk is low and the cost burden less significant and so fuel-cost pass-through mechanisms have received
21 little attention in the recent past. The question for the Commission is what is “just and reasonable” in the
22 allocation of fuel costs when low fuel prices are no longer the norm.

23 Two underlying factors have altered the bargain under fuel-adjustment provisions. First, fuel led
24 by natural gas has entered a period of rapid and extreme price volatility. On its face it is not reasonable to
25 assume that either customers or the utility can absorb fuel-cost changes of this magnitude in their household

1 or business operating budgets, respectively. Unrestrained fuel costs create a no-win situation for the
2 Commission to allocate unreasonably large and unpredictable costs from which no one benefits.

3 The second change in the landscape in the last decade is greatly reduced costs (up to 80 percent
4 reductions) for fuel-free alternatives, including solar, wind, storage and efficiency. Because these resources
5 use no fuel they hedge fuel prices, lowering the fuel-cost burden on customers and the utility. Georgia
6 Power has experience with and referenced those fuel-cost hedging benefits in their testimony. Those
7 benefits are limited currently by the comparatively small levels of renewable energy in the portfolio.

8 A greater share of renewables in the generation portfolio, in addition to lowering and stabilizing
9 rates for customers offers an increased investment opportunity. With no fuel costs, virtually all of the
10 levelized energy cost is capitalized up front, which means a very secure and stable capital investment with
11 commensurate investment opportunities. Under well-established competitive procedures for securing those
12 needed resources at the best price, the utility could potentially capitalize on those investments and earn a
13 profit on them, which as it noted it does not earn on purchasing fuel for the current portfolio.

14 **Q: WITH REGARD TO THE INCREASING BURDEN POSED BY FUEL PRICES, HOW**
15 **SHOULD THE COMMISSION ASSESS THE MAGNITUDE OF CURRENT FUEL GAS PRICE**
16 **SWINGS?**

17 **A:** Fuel prices have risen in multiples above the low-price assumptions used by Georgia Power in
18 previous planning and resource decisions. Georgia Power described the cost increases as “unprecedented”:

19 For electric utilities, like Georgia Power, the impact of elevated fuel prices – particularly the price
20 of natural gas, which more than tripled between 2020 and 2022 – was especially acute, given their
21 reliance on natural gas as a critical fuel resource to generate electricity. In addition to natural gas,
22 commodity prices for coal – another critical fuel resource for electric utilities – reached
23 unprecedented levels, increasing nearly five-fold from 2020 to 2022. (Direct Testimony of Sarah
24 P. Adams and Adam D. Houston On Behalf of Georgia Power Company Docket No. 44902 Page
25 5 of 23.)
26

27 The utility has under-recovered fuel costs of \$2 billion over 2 ½ years and projected the bill could
28 reach \$2.6 billion, due to low fuel-cost assumptions. As I will describe later, these cost increases are actually
29 *not* unprecedented.

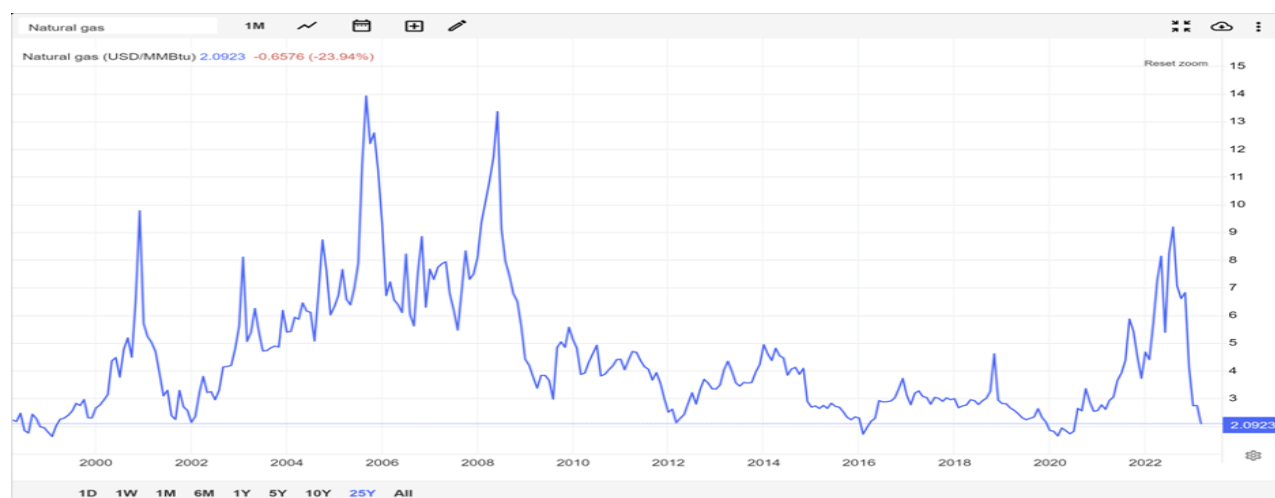
Q: WHAT ARE THE IMPACTS OF THESE MUCH HIGHER FUEL COSTS ON CUSTOMERS AND THE UTILITY?

The impact on the utility customers is an electric bill increase as sudden and extreme as the increase in fuel costs. There are few options to mitigate the \$2.6 billion of excess cost. The utility has proposed spreading recovery of the shortfall over the next three years and increasing by \$2 per month relief for seniors to ease the burden. Reducing the immediate customer burden at any level is of course desirable and necessary in the current circumstances, but it doesn't solve the underlying problem. Without a plan to address heavy dependency on natural gas fuel cost overruns will continue to burden customers and crowd out headroom for necessary improvements and investments by the utility going forward.

Q: WITH NATURAL GAS PRICES HAVING COME DOWN CAN THE COMMISSION AND RATEPAYERS ASSUME THESE LARGE FUEL COST SPIKES WON'T HAPPEN AGAIN?

A: No. The risk of increased fuel prices and volatility rises over the next decade. Recent price swings are not the result of short-term supply and demand issues. As Georgia Power accurately summarized in its pre-filed testimony, the price increases and volatility are the result of structural changes in global markets for natural gas, the exposure to which is expanding here in the U.S. We have entered a market where global forces dominate natural gas prices. Here is the curve of natural gas prices over the last 25 years:

Figure 1



1 It is easy to see on this chart that while recent price increases are unprecedented in the last decade,
2 they are not unprecedented overall. The recent swings are actually smaller and just beginning in comparison
3 to the size of price swings and duration of price volatility experienced in the prior decade. The current
4 drivers of natural gas markets are global with larger and less predictable forces. As Georgia Power
5 confirmed in its testimony, geopolitical unrest and increasing absorption of domestic production for global
6 demand with proliferation of Liquid Natural Gas (LNG) terminals in the U.S. now drive natural gas prices.
7 More LNG export terminals are scheduled to come on-line on the East and Gulf Coasts in 2024. Some have
8 described these export terminals as potentially “starved” for natural gas supply. At a minimum each
9 terminal brings competing demand and opens further exposure to global market forces.

10 Continued high price volatility assumed by Georgia Power is consistent with current industry
11 prognoses. A recent article in the commodity trade press summarized prospects of continued natural gas
12 volatility as follows:

13 "I think volatility is here to stay for the foreseeable future," Citi analyst Paul Diamond told *Argus*.
14 "The underlying issues causing that step change in the last 24 months are not going away." If one
15 measures volatility by the number of days an asset moves by more than 7 percent in value, 2022
16 was the most volatile year for natural gas prices since at least the beginning of the shale era. In
17 2022, the price for day-ahead delivery at the US benchmark Henry Hub in Louisiana rose or fell
18 by more than 7 percent on 65 occasions, the most of any year since at least 2009, according to an
19 *Argus* analysis. So far, the Henry Hub has done so 21 times this year. At that rate, 2023 will be
20 more volatile than 2022.¹

21 The dangers posed by future price swings is multiplied by the asymmetric risk of fuel price changes.
22 Given the low fuel-price assumptions in the past, potential savings from downswings in fuel prices are
23 extremely limited, maybe \$1/MMBtu at most since prices stay above zero, whereas there is no cap on
24 increasing prices that rise by several hundred percent to \$14/MMBtu or more as shown on the historical
25 price chart.

26 **Q: WHAT ASSUMPTIONS SHOULD THE COMMISSION USE FOR FORECASTING**
27 **NATURAL GAS PRICES AND PRICE VOLATILITY GOING FORWARD?**

¹ Argus Media. “US Gas Price Volatility Likely To Continue.” [Published](#) on 28 March 2023.

1 **A:** The Commission should use the planning assumptions presented by Georgia Power in this case,
2 which are higher natural gas prices and greater volatility. Georgia Power properly recognized the need
3 going forward “to respond to the type of sudden and extreme fuel price volatility that impacted global fuel
4 markets during the FCR-25 period.” (Direct Testimony at page 4 of 21). The response proposed in this case
5 is a 267% increase (from 15% to 40%) in the amount of future fuel cost increases that would automatically
6 pass through to customers under the Interim Fuel Recovery Mechanism, without advance review by the
7 Commission (Direct Testimony at page 4 and 21).

8 **Q: WHAT DOES THAT MEAN FOR UTILITY CUSTOMERS AND THE UTILITY?**

9 **A:** What it means is more, not less, customer exposure to fuel price increases. It may mean fewer cases
10 like this to review bill increases but expanding the Interim Fuel Recovery Mechanism will allow multiple
11 bill adjustments like this as routine rather than extraordinary events. Planning for more frequent and larger
12 price pass-throughs is consistent with Georgia Power’s assessment of the structural changes to natural gas
13 markets that now determine prices. This is not a one-off event. Georgia Power also pointed out that fuel-
14 price exposure has increased because it has increased natural gas fired generation in its portfolio, which
15 multiplies any given fuel price increase into higher total dollar fuel costs passed on to customers. Whether
16 less Commission review of future fuel-cost pass-throughs is the right response is the underlying issue in
17 this case.

18 **Q: ARE THERE WAYS TO MITIGATE FUEL COSTS AND FUEL COST VOLATILITY TO**
19 **AVOID RATE-SHOCK IN THE FUTURE?**

20 **A:** Yes, Georgia Power referenced it in the direct testimony of Ms. Adams and Mr. Houston. After
21 noting that the dollar per megawatt-hour costs for coal, natural gas, and nuclear generation resources are
22 projected to increase 97%, 82%, and 17%, respectively, the testimony stated that renewable generation
23 lowers the cost of fuel, adding a planned increase in renewable resources:

24 “Generation from renewable resources – which lowers the cost of fuel – is estimated to increase
25 almost 1,150 gigawatt hours (“GWh”) or 41%.” (Direct Testimony of Ms. Adams and Mr. Houston
26 at 15).
27

1 That current planned increase in renewables amounts to about 1.4% of total load.

2 At the average price of \$5.14 per mmbtu projected for FCR-26 test period (Direct Testimony of
3 Ms. Adams and Mr. Houston at 15) the increase in renewable resources proposed by Georgia Power saves
4 about \$140 million over the three-year period proposed for recovery of the fuel cost excess. By comparison,
5 under the same assumptions, adding solar generation equal 10% of total load would save about \$1 billion
6 in fuel costs over three years and additionally thereafter.

7 **Q: THAT LEVEL OF FUEL SAVINGS WOULD CERTAINLY BE WELCOMED BY**
8 **CUSTOMERS. HOW WOULD IT WORK FOR THE UTILITY?**

9 **A:** The economics of solar and other renewables at utility scale are competitive with natural gas and
10 coal fired generation on a levelized-cost-of-energy basis. That means, simply by buying renewable energy
11 under long-term contracts, the utility can lock in energy savings and hedge against future fuel price swings.

12 As mentioned, capital investment in renewable energy generation offers additional benefits for the
13 utility if the Commission allows such investments. With no fuel costs, virtually all of the levelized cost of
14 renewable energy is upfront capital expense, with very low ongoing-operating costs. Twenty-five-year
15 product warranties are standard for solar projects, which now have decades of proven operating history and
16 rock-solid results with no volatility and no surprises. That is a gold standard for capital investment. With
17 no fuel cost, dollars formerly expended on fuel are invested as upfront capital.

18 As an example, based on the numbers in this case, adding another 10% solar would mean about 3.5
19 gigawatts of new solar capacity, which after accounting for tax credits would mean a total capital
20 expenditure approximately the same as the amount sought in recovery in this one fuel case. In addition to
21 bill savings for customers, utility investment in some part of that portfolio would increase utility earnings,
22 strengthening the financial health of the utility, which is always a consideration of the Commission. This
23 has been described as a “steel for fuel” strategy and brings the win-win benefits of renewable energy home
24 to the broadest range of Georgia beneficiaries.

25 There are additional economic development benefits available from investing in renewable energy.
26 Under last year’s Federal amendments, there are significant adders to the applicable tax credits for domestic

1 content and for preferred redevelopment sites in the state. In addition, in the state-on-state competition for
2 U.S. based manufacturing, which has experienced a surge of proposals, sites that cannot offer clean
3 renewable electricity have lost out to competing sites that can. Given that the fundamental economics are
4 favorable, there is no reason not to capitalize on the economic development benefits that come with it.

5 Competitive procurement of renewable generation allows the Commission to assure the most
6 savings for customers and establishes market investment returns should the Commission choose to allow
7 utility investment and profit on additional investment. Other states have effectively used competitive
8 procurement to lower the capital expenditures and in some instances divided a portfolio of projects between
9 utility and independent ownership. Competitive procurement to assure the best price for renewable
10 resources has resulted in favorable and unexpectedly low costs for adding renewable resources to utility
11 portfolios. Georgia Power used competitive bidding to procure solar power in the past and would
12 undoubtedly get vigorous bid competition in further procurement. Competitive procurement and potential
13 utility project ownership are two of the most effective tools the Commission has to secure the new energy
14 economics available to counter increases like the ones faced in this proceeding. Both of those proven
15 approaches should be adopted by the Commission.

16 **Q: YOU MENTIONED THAT FUEL CASES HAVE TRADITIONALLY SIMPLY PASSED**
17 **FUEL COSTS DIRECTLY THROUGH TO CUSTOMERS IN INCREASED RATES. WHAT ELSE**
18 **SHOULD THE COMMISSION DO?**

19 **A:** In fuel cases like this, the Commission is looking to review, manage and allocate fuel price risk.
20 Given the consensus that economic and market circumstances elevate the risk of continued fuel price hikes,
21 determining what is “just and reasonable” will require the Commission to investigate and address the
22 sudden and extreme price increases to date.

23 Georgia Power accurately explained that the current elevated fuel risk derives from the combination
24 of (i) changing global markets, which are accelerating and here to stay, and (ii) increased share of natural
25 gas generation in its portfolio. The market changes are reasonably clear and outside of the control of Georgia
26 Power and the Commission. The concentration of natural gas generation is under the control of Georgia

1 Power and the Commission and arises from multiple decisions in multiple dockets, including IRPs, rate
2 cases, avoided cost dockets and energy efficiency proceedings. A quick review of the economics of
3 renewable energy as a cost-effective hedge to natural gas market changes in this case shows the need for
4 the Commission to update the resource portfolio economic assumptions as part of a just and reasonable
5 determination.

6 **Q: HOW SHOULD THE COMMISSION DO THAT?**

7 **A:** The first step is updated fuel price assumptions across all resources and planned resource additions
8 to assure that the Commission has an updated assessment of fuel price impacts. That is a clear first step to
9 assure customers that the Commission is on top of fuel price risks and taking the necessary steps to mitigate
10 fuel risk on their behalf.

11 The economics compel an update of fuel price assumptions across the generation portfolio (whether
12 previously included in the 2022 IRP or other dockets). The goal is to avoid spending short-term dollars on
13 fuel when those same dollars could deliver greater short- and long-term savings and returns. The rapid
14 market changes leading to this case demonstrate the urgency of getting updated assumptions in place now
15 before next round of fuel price swings.

16 The second step is to align utility and customer interests in decisions on fuel costs and capital
17 investment. As a starting point the utility might bear a percentage of the fuel-price risks of the current
18 portfolio in return for expanded investment opportunity in a more price-stable future portfolio.

19 Since there are alternatives that are win-wins for both Georgia Power and its customers, detailing
20 those alternatives is the Commission's next step. The Commission deserves to have the options identified
21 and quantified with current data to avoid more surprises.

22 **Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.**

23 **A:** In summary, I recommend that the Commission in this proceeding or in a proceeding opened for
24 this purpose:

- 25 • Make a finding based on the facts presented in this case and to protect customers from
26 unreasonable fuel-cost increases, that a high-case projection of fuel prices, volatility and

1 risk needs to be included as the base-case assumption in resource decisions and planning
2 going forward;

- 3 • Update fuel-cost assumptions and quantify potential cost savings and investment returns
4 as well as other future and long-term benefits from adding fuel-free renewable generation
5 to the utility portfolio above the levels currently proposed; and
- 6 • Establish a just and reasonable percentage of fuel-price risk in the current portfolio to be
7 borne by the utility in return for expanded investment opportunity in a more price-stable
8 future portfolio.

9
10 **Q: DOES THAT CONCLUDE YOUR TESTIMONY?**

11 **A:** Yes, it does.

R Brent Alderfer

brent.alderfer@communityenergyinc.com

Professional Summary

Brent Alderfer is a seasoned entrepreneur and renewable energy expert with extensive experience in the development of utility-scale wind and solar energy projects. With a background in electrical engineering and law, he founded Community Energy, Inc., a leading renewable energy firm. Under his leadership, the company became a major player in the renewable energy industry, providing renewable projects and related market services to utilities and businesses across the country. The Company sold its wind energy development business to Iberdrola in 2006 and sold its solar energy development business to AES in 2021.

Education

- Bachelor of Science in Electrical Engineering, Northeastern University
- Law Degree, Georgetown University

Work Experience

- Founder and CEO, Community Energy, Inc.
 - Led the company's growth and expansion into a major player in the renewable energy industry
 - Developed wind and solar projects across the United States
 - Provided renewable energy products and services to utilities and businesses
- Commissioner, Colorado Public Utility Commission (1996-1999)
- Commercial Lawyer, various law firms (1980s-1990s)
 - Represented commercial clients on corporate, finance and regulatory matters

Skills

- Renewable energy project development
- Finance, renewable energy projects
- Policy, regulatory compliance
- Leadership and team management
- Strategic planning and business development

R Brent Alderfer

brent.alderfer@communityenergyinc.com

Accomplishments

- Ernst & Young Entrepreneur of the Year Award
- Sustainable Energy Fund, Pennsylvania, Lifetime Achievement Award
- Member of various industry and environmental organizations

Interests, Organizations

- New Energy Economics
- MEDA, International Development
- Philanthropy and community involvement
- Farming
- Outdoor, skiing, running, hiking

CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Albert Lin on behalf of Georgia Interfaith Power & Light and Southface Institute** was filed with the Public Service Commission in Docket No. 56765 by electronic delivery on the 9th of April, 2026. An electronic copy of same was served upon all parties listed below by electronic mail as follows:



Bob Sherrier

Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
stanner@psc.ga.gov

Justin Pawluk
Chris Collado
Tom Newsome
Robert Trokey
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334
jpawluk@psc.ga.gov
ccollado@psc.ga.gov
tnewsome@psc.ga.gov
rtrokey@psc.ga.gov

Joshua W. Combs
Steven J. Hewitson
Brandon F. Marzo
Allison W. Pryor
Troutman Pepper Locke LLP
Bank of America Plaza
600 Peachtree Street, NE
Suite 3000
Atlanta, Georgia 30308-2216
josh.combs@troutman.com
steven.hewitson@troutman.com
brandon.marzo@troutman.com
allison.pryor@troutman.com

Jeremiah Haswell
Director, Regulatory Affairs
Georgia Power Company
241 Ralph McGill Boulevard, NE
Bin 10230
Atlanta, Georgia 30308
jhaswell@southernco.com

Charles B. Jones, III
Jim Kelleher
Georgia Association of Manufacturers
75 Fifth Street NW
Suite 3412
Atlanta, Georgia 30308
cjones@gamfg.org
jkelleher@gamfg.org

Jeffrey C. Pollock
J. Pollock Incorporated
14323 South Outer 40 Road, Suite 206N
Town and County, Missouri 63017
jcp@jpollockinc.com

Isabella Ariza, Esq.
Sierra Club
50 F Street NW, 8th Floor
Washington, D.C., 20001
Isabella.ariza@sierraclub.org

Maggie Shober
Southern Alliance for Clean Energy
P.O. Box 1842
Knoxville, Tennessee 37901
maggie@cleanenergy.org

Patrick King II
Natural Resources Defense Council
1152 15th Street NW, #300
Washington, D.C. 20005
pkingii@nrdc.org

Robert B. Baker
Robert B. Baker, PC
2480 Briarcliff Road NE, Suite 6
Atlanta, Georgia 30329
bobby@robertbbaker.com

Jim Clarkson
Resource Supply Management
135 Emerald Lake Road
Columbia, South Carolina 29209
jclarkson@rsmenergy.com

1 MR. KAMANI: Thank you. I would also ask
2 that Exhibits AL-1 through 3 that were attached to
3 his prefiled direct testimony be marked for
4 identification as GIPL/SF 17, 18, and 19.

5 CHAIRMAN SHAW: So marked.

6 (The documents referred to were marked for
7 identification as GIPL/Southface Exhibit 17, 18 and
8 19.)

9 MR. KAMANI: Thank you.

10 BY MR. KAMANI:

11 Q. Mr. Lin, did you prepare a summary of your
12 testimony?

13 A. I did.

14 MR. KAMANI: Mr. Chairman, with your
15 permission, I'd like to ask Mr. Lin to read his
16 summary.

17 CHAIRMAN SHAW: Yes, sir.

18 Go ahead, Mr. Lin.

19 MR. LIN: Thank you, Commissioner.

20 Good afternoon all the Commissioners. My
21 name is Albert Lin and I am presenting testimony on
22 behalf of Georgia Interfaith Power & Light and
23 Southface Institute.

24 I'm a consultant at the OG Finance Lab. I've
25 testified in a number of fuel case dockets and rate

1 cases across the country, including throughout the
2 southeast. I've previously testified before this
3 Commission in 2024 in the Georgia Power Yates
4 Certification Hearing, Docket Number 55378.

5 In this docket, I reviewed Georgia Power
6 Company's application for fuel cost recovery and
7 related requests. And based on my review, I've
8 identified two key issues.

9 First, natural gas price volatility is
10 putting upward pressure on Georgia Power's fuel
11 costs. Georgia Power is relying more and more
12 heavily on natural gas for their electricity
13 generation. That approach is risky because natural
14 gas is far more volatile in price than any other
15 major fuel source, and that price volatility is
16 increasing in recent years, as shown on pages 18
17 through 19 of my testimony and in Figures 8, 9, and
18 10.

19 Georgia Power's residential customers already
20 spend 27 percent of their total electric bill on
21 fuel costs, with natural gas being the largest cost
22 category. As the company increases its exposure to
23 the most volatile price-volatile generation
24 technology, the customers will likely experience
25 continued upward pressure on fuel costs.

1 As I discussed in pages 16 and 17, and in
2 Figure 7 of my testimony, the rapid increase in
3 liquefied natural gas exports from the United
4 States will likely continue to accelerate. And
5 that significant increase in demand for the U.S.
6 LNG is likely to raise natural gas prices
7 domestically.

8 In this year's FCR filing, the roughly
9 \$5.74-per-month decrease in customer bills that
10 Georgia Power projects in this proceeding, it
11 masked the fact that underlying fuel costs continue
12 to rise. On page 10 of my testimony, Figure 3
13 shows this phenomenon.

14 Starting in the last fuel cost docket,
15 Georgia Power has used a two-part fuel rate;
16 Part A, which estimates the rate needed to cover
17 projected fuel costs, and then a Part B, which
18 estimates the rate needed to repay past fuel costs
19 that were under-recovered.

20 In this proceeding, Georgia Power proposes
21 increasing the Part A charge by about 13 percent.
22 Those increases are driven by projected cost
23 increases in natural gas. The only reason that the
24 fuel charge on customer bills will decrease at the
25 start of this FCR period is a large reduction in

1 Part B costs, which results from customers finally
2 paying off the substantial under-recovery balance
3 that Georgia Power accrued in 2022. So even though
4 customer fuel charges will decrease in FCR-27, the
5 underlying fuel costs have continued to rise
6 substantially over the past three FCR periods.

7 The second issue I'd like to bring up is
8 the -- Georgia Power's request in this docket to
9 expand its natural gas hedging program and increase
10 the interim fuel rider, or IFR threshold, would
11 reduce transparency around the company's fuel
12 costs.

13 As to the hedging program, hedging obscures
14 the financial risk of Georgia Power's heavy
15 reliance on natural gas. Hedging is like buying
16 insurance. If Georgia Power wants to cap the price
17 for the natural gas it purchases, the counterparty
18 must agree to absorb the price volatility risk.
19 That counterparty will charge a rate, essentially
20 an insurance premium, that allows it to profit over
21 time. So increasing hedging may keep customers'
22 costs steadier, but it will keep them steadily high
23 over time.

24 A further problem with Georgia Power's
25 hedging program is that because Georgia Power can

1 pass through 100 percent of its hedging cost to
2 customers, it bears none of the hedging cost
3 itself, and, therefore, lacks incentive to identify
4 the optimal amount of hedging for its customers.

5 My testimony supports the financial alignment
6 of interests for both customers and Georgia Power.
7 For that reason, I support Witness Kalin's
8 recommendation that the Commission initiate a
9 separate docket to explore fuel-cost sharing.

10 As to the interim fuel rider, or IFR, because
11 Georgia Power is deepening its reliance on natural
12 gas at a time when volatility -- price volatility
13 is increasing, the current IFR threshold is more
14 likely to be exceeded. But increasing the IFR
15 threshold doesn't solve any problems. It just
16 hides the significant cost increases from public
17 view for a longer period.

18 So in light of these findings, I have four
19 recommendations for how the Commission should
20 increase oversight and transparency for fuel cost
21 recovery.

22 First, the Commission should deny Georgia
23 Power's request to increase the IFR limit.
24 Maintaining the current limit will allow the
25 Commission and the public to better monitor and

1 respond to fuel cost changes as they occur.

2 Second, the Commission should reduce the
3 maximum amount by which fuel rates can be adjusted
4 when the IFR threshold is reached from 40 percent
5 down to 15 percent. Allowing Georgia Power the
6 flexibility to increase rates up to 40 percent in
7 between FCR proceedings would further encourage use
8 of price-volatile fuels, and the -- and the
9 15 percent rate is five times or 500 percent higher
10 than the current rate of inflation, and that
11 represents a reasonable maximum level without
12 specific Commission approval.

13 Third, the Commission should set a date for
14 the next fuel cost rider hearing. Given Georgia
15 Power's rising fuel costs and increased exposure to
16 the most price-volatile fuel, the FCR cases are
17 more important than ever.

18 Fourth, and finally, the Commission should
19 order Georgia Power to add a fuel cost line item on
20 the monthly bill for all customers. Because
21 customers currently must opt in to an itemized
22 bill, most customers are likely unaware of the size
23 of fuel costs and the extent of fuel price
24 volatility over time. Disclosing fuel costs on
25 customer bills would help resolve that lack of

1 transparency.

2 Thank you for your time. I welcome any
3 questions you may have.

4 VICE-CHAIRMAN MCDONALD: Mr. Lin, was your
5 fifth recommendation burning more coal?

6 MR. LIN: I -- I -- I don't have any
7 recommendations specifically on using more or less
8 coal. I'm just saying make an optimized financial
9 aligned, motivated choice.

10 VICE-CHAIRMAN MCDONALD: Your -- your
11 testimony was based around cost.

12 MR. LIN: It is.

13 VICE-CHAIRMAN MCDONALD: Is fuel by coal
14 cheaper than gas?

15 MR. LIN: Not always. Looking back, it
16 depends on the price of natural gas, which is
17 extremely volatile. So there are times when coal
18 can be more or can be less.

19 VICE-CHAIRMAN MCDONALD: All right. Thank
20 you.

21 MR. KAMANI: Mr. Chairman, Mr. Lin is now
22 available to answer questions from the Commission
23 and for cross-examination from Commission staff and
24 other parties.

25 CHAIRMAN SHAW: All right. Thank you,

1 Mr. Kamani.

2 Commissioners.

3 COMMISSIONER HUBBARD: I have a few
4 questions, if you don't mind.

5 CHAIRMAN SHAW: Yeah. Go ahead.

6 COMMISSIONER HUBBARD: Mr. Lin, I really
7 appreciated Figure 3. I thought that was useful to
8 highlight the difference between Part A and Part B.

9 And I noticed between FCR-25 and FCR-27, that
10 Part A -- this is on page 10 -- has been increasing
11 steadily. And you mentioned a couple of market
12 forces, like LNG exports and increasing demand from
13 new customers, the build-out of gas-fired
14 generation resources.

15 Is it your opinion that that -- that
16 forecasted part, the fuel cost, is going to
17 continue to increase, or do you see a world in
18 which maybe those costs might go down in the
19 future?

20 MR. LIN: I think the general trend is likely
21 to be up simply based on the number of public
22 companies that are producing natural gas and
23 transporting and storing natural gas and their
24 investments being so heavily focused on LNG.

25 I think you have probably seen all the FERC

1 permits and the construction of LNG. We know
2 there's a tremendous amount of building to meet
3 this export demand at higher prices. I think the
4 industry is now believing in that and supporting it
5 with the other infrastructure, which then means
6 less natural gas available domestically at prices
7 that would have to compete with the international
8 market.

9 COMMISSIONER HUBBARD: And then you also
10 mentioned that you believe that instead of a
11 40 percent threshold for how much can be hedged, it
12 should be much less than that, 15 percent. So in a
13 world in which that was approved to go down to
14 15 percent, what would be some other ways that you
15 could mitigate price volatility and -- and ensure
16 rate stability?

17 MR. LIN: Okay. First, just to be clear, the
18 40 percent to 15 is the automatic bill adjustment
19 from the IFR. But regards to -- I think you were
20 specifically asking about hedging amounts. Other
21 than hedging, the primary tool that most financial
22 institutions would look at is to use a portfolio
23 effect to basically diversify your energy sources
24 and recognize the volatility and financial risk of
25 committing "X" percent to a particular product or

1 technology.

2 In this case, natural gas is the largest. So
3 it's somewhat easy to pick on just because of its
4 substantial size and impact financially. But if it
5 were another fuel, I would be up here warning you
6 to be careful about letting Georgia Power or any
7 other utility overinvest or commit or rely on one
8 particular technology.

9 COMMISSIONER HUBBARD: Okay. Thank you.

10 Last question. I noticed in your CV that you
11 had worked on other -- in other states, including
12 Colorado SB-291. And I just wondered -- and this
13 was related to fuel cost recovery adjustments. Are
14 there any lessons learned from your work in other
15 states that might be applicable here to Georgia?

16 Some -- some, you know, best practices that
17 you've seen, in particular after SB-291 and maybe
18 the -- you know, having some -- some years of
19 hindsight to look back.

20 MR. LIN: Yes. I think -- I think over the
21 years various Commissions are starting to
22 understand that a focus on high volatile fuel price
23 technologies is resulting in probably that being
24 the largest contributor to affordability. That is
25 what started the work in Colorado. They had to do

1 an audit to see why they had the highest number of
2 Commission complaints in the history of the state.
3 And it was all about affordability and fuel costs
4 and their utility bills rising far faster than the
5 rate of inflation.

6 Because of that work, they decided they must
7 focus on aligning incentives so that the utility
8 really thinks about whether they wanted to continue
9 to invest in high-price volatile fuels and that's
10 what started the process of asking the Commission
11 to devise a mechanism for fuel-cost sharing.

12 COMMISSIONER HUBBARD: Last question. So the
13 portfolio diversification, can you just -- for the
14 record, what is the fuel price and the fuel price
15 risk of, for example, solar and wind?

16 MR. LIN: Well, obviously, as reported by the
17 company, there is no meaningful fuel price for wind
18 or solar. Those costs are the natural financial
19 analysis and trade-off of investing in something
20 upfront in the hopes of benefiting from low
21 operating costs in the future. The negatives, of
22 course, are the intermittency and other physical
23 issues that then you have to manage, potentially
24 with other costs, and Georgia Power is looking at
25 it, such as battery energy storage solutions, to

1 complement those technologies.

2 But I don't think anyone can have a fair
3 analysis of these different technologies when the
4 entire fuel cost, which is the largest operating
5 cost, is being paid by another party. I think
6 there's a natural moral hazard of having that set
7 up. And it's nobody's fault because we started in
8 a world where everything required fuel cost.

9 The world has changed to where there's many
10 technologies that don't involve fuel. I just feel
11 it's very uncompetitive and unfair in the
12 marketplace for some businesses to have to compete
13 with other businesses that have a large portion of
14 their operating costs removed that they already
15 don't have as a starting point.

16 COMMISSIONER HUBBARD: Thank you.

17 CHAIRMAN SHAW: All right. Any other
18 questions?

19 (No response.)

20 Moving on. Georgia Public Service
21 Commission.

22 CROSS-EXAMINATION

23 BY MR. COLLADO:

24 Q. Mr. Lin, the -- you discussed a risk-sharing
25 proposal in your testimony regarding fuel cost; correct?

1 A. Yes.

2 Q. The 10 percent, yes.

3 Would the risk sharing, as you propose,
4 incentivize over-forecasting fuel costs on the part of
5 Georgia Power?

6 A. Okay. We have to back up for a
7 clarification. In this -- in this hearing, I think you
8 may be thinking of witness -- are you talking about
9 Jeremy? Yeah.

10 Q. Mr. Kalin.

11 A. Now, I support some of his ideas, but I am
12 not proposing any particular fuel-cost sharing mechanism.

13 Q. Okay. I understand. Thank you for
14 clarifying that.

15 A. Okay.

16 Q. Did you testify that GPC customers can --
17 yeah. You mentioned in your statement that Georgia Power
18 customers cannot see fuel cost components on their
19 bills -- correct? -- and that providing this detail would
20 be beneficial.

21 Would providing this detail improve customer
22 awareness and help limit long-term fuel cost growth?

23 A. I think it may. It's hard to tell what
24 customers would do with new information that they
25 currently do not see. So I don't want to try to even make

1 that forecast.

2 But I would say we know for sure most
3 customers do not see that. And I work with Georgia Power
4 customers to see how they could opt in to see that detail
5 on their bill. And I will say nobody was successful and
6 it's very difficult. You cannot do it online in any way
7 we could find.

8 Q. And similarly --

9 COMMISSIONER JOHNSON: May I ask -- I'm
10 sorry.

11 MR. COLLADO: I'm sorry, Commissioner. Did
12 you have a question?

13 COMMISSIONER JOHNSON: I do. I just wanted
14 to back up in between the two questions that you
15 just asked Mr. Lin.

16 If you could just clarify. Cost sharing
17 would require the company to bear a portion of the
18 fuel risk; correct?

19 I know you're not recommending a particular
20 model, but...

21 MR. LIN: I -- I do -- I do think I
22 understand your question. And -- and it depends on
23 how you design the mechanism.

24 I am not a proponent of automatically forcing
25 the utility to pay a share of the fuel cost. I am

1 -- I am in support of mechanisms that align the
2 interest so that there is the potential for them to
3 pay some of the fuel costs. And, equally, there is
4 a potential they could earn credits for being more
5 efficient.

6 COMMISSIONER JOHNSON: Okay.

7 MR. LIN: So my view is: How do you incent
8 their financial outcome to their shareholders more
9 in line with what the customers would like to see
10 so that their decisions are made sort of on behalf
11 of both the benefit of the customer and the
12 utility?

13 COMMISSIONER JOHNSON: Okay. I just wanted
14 to clarify that what -- what you're suggesting is
15 that some model be included that would improve
16 incentives for cost control.

17 MR. LIN: Yes.

18 COMMISSIONER JOHNSON: So the customers are
19 not bearing the full financial risk of
20 mismanagement over just the entire volatility of
21 the -- of the current model.

22 MR. LIN: That's correct.

23 COMMISSIONER JOHNSON: Okay. Thank you.

24 We're clear.

25 BY MR. COLLADO:

1 Q. And my last question. You recommended
2 reducing the IFR adjustment cap from 40 percent to
3 15 percent; correct?

4 A. That's correct.

5 Q. Okay. Would you support staff's position on
6 an IFR adjustment to be allowed only quarterly, even if
7 staff didn't recommend changing the cap?

8 A. Right. Repeat that again.

9 Q. So staff's position -- staff didn't make a
10 recommendation on the adjustment cap itself. But they did
11 make a recommendation about how IFR adjustments should
12 only be allowed quarterly.

13 Is that something that you would support?

14 A. Yes. I think the timing is fine for
15 quarterly.

16 MR. COLLADO: Okay. All right. No further
17 questions.

18 COMMISSIONER HUBBARD: I just want to add one
19 comment that -- to your fourth recommendation of
20 adding fuel cost, specifically a line item in
21 bills. I do see it not on the bills, but on the
22 bill calculator that the Public Service Commission
23 has on their website.

24 So it's possible to get it for a generic
25 bill, but just not on your specific bill, unless

1 you have to go and request it.

2 MR. LIN: Right. But -- but is it designed

3 in a way that you have to theoretically know your

4 kilowatt-hour consumption?

5 Isn't that on the -- you have to already know

6 a number of things; your tariff rate, your actual

7 electricity usage. So, you're right, it could

8 probably be estimated if you took your actual bill

9 and then filled in the inputs. But I think -- I

10 think it should just be much easier.

11 COMMISSIONER HUBBARD: Yep. It's an extra

12 step right now.

13 CHAIRMAN SHAW: All right. Georgia

14 Association of Manufacturers.

15 MR. JONES: No questions.

16 CHAIRMAN SHAW: Georgia Interfaith Power &

17 Light and Southface.

18 MR. KAMANI: That's GIPL.

19 CHAIRMAN SHAW: Oh, I'm sorry. I'm sorry,

20 y'all. It's a long day.

21 MARTA.

22 MR. BAKER: No questions.

23 CHAIRMAN SHAW: Resource Supply Management.

24 (No response.)

25 CHAIRMAN SHAW: Sierra Club, SACE.

1 MS. ARIZA: No questions.

2 CHAIRMAN SHAW: Georgia Power.

3 CROSS-EXAMINATION

4 BY MS. PRYOR:

5 Q. Good afternoon, Mr. Lin. Good to see you
6 again.

7 Regarding the IFR threshold, you disagree
8 with the company's recommendation to increase it from 200
9 to 300 million; correct?

10 A. I do.

11 Q. And your primary objection to the increase is
12 due to claims that the 300 million threshold hides
13 significant cost increases from public view for a longer
14 period; right?

15 A. That's right.

16 Q. And if the 200 million threshold is
17 maintained, you'd -- you'd agree that it may result in
18 more frequent rate changes, though; correct?

19 A. That's true.

20 Q. Okay. Are more frequent rate changes better
21 for customers?

22 A. I don't think it matters as much simply
23 because, in the end, the full cost will be accounted for
24 and paid for by the customer. So putting it on payment
25 plans or the exact timing I think is of moderate interest,

1 but is certainly not the primary consideration.

2 Q. And you also recommended the Commission
3 reduced the maximum amount by which fuel rates can be
4 adjusted during an FCR period from the current 40 percent
5 level down to 15 percent level for the IFR; correct?

6 A. That's right.

7 Q. Now, in response to a question from
8 Commissioner Hubbard, I just wanted to -- to clarify.
9 This is not an automatic adjustment with an -- with the
10 IFR. The Commission would still have to approve any
11 change; correct?

12 A. Yes.

13 Q. Okay. And the maximum adjustment for the IFR
14 between fuel cases used to be 15 percent; correct?

15 A. That's right.

16 Q. And that -- that amount was changed in
17 FCR-26; right?

18 A. That's right.

19 Q. And the company's request to modify the
20 adjustment from 15 to 40 percent was due to the fact that
21 the 15 percent adjustment on a large under-recovered
22 balance was insufficient to bring the fuel balance back to
23 zero; correct?

24 A. That's right.

25 Q. Okay. And you didn't provide any evidence or

1 analysis that 15 percent would be more effective than
2 40 percent, did you?

3 A. In the end, none of them are more or less
4 effective because the full amount is recovered. So
5 they're equally effective; it's a matter of timing and how
6 it's processed. My point and my analysis was when
7 customers think of what would be a reasonable amount to
8 see an automatic change in a large item, such as fuel in
9 their bill, five times the rate of inflation is a
10 reasonable cap.

11 Q. Okay. And we'd agree it's not automatic;
12 right?

13 A. Right.

14 Q. Okay. But you didn't -- there's no magic to
15 the 15 percent. You just offered that as an alternative
16 --

17 A. No.

18 Q. -- and something lower than 40; correct?

19 Okay. If a rate adjustment less than
20 40 percent can bring the fuel balance back to zero, then
21 Georgia Power could adjust rates something less than 40;
22 right?

23 40 percent is just a maximum?

24 A. Well, I didn't get into any particular
25 maximums or minimums. I just think 15 percent is a far

1 more reasonable range. I would leave it to the discretion
2 of the Commission because, in the end, I am advocating
3 that they review it all in total to decide what is
4 reasonable and prudent. But, in my mind, going back to
5 the former 15 percent makes a lot more sense than taking
6 the 40 percent and continuing with it.

7 Q. But as currently structured, the 40 percent
8 threshold in the IFR is a maximum. So the company could
9 elect to make a 15 percent change under the current
10 structure; right?

11 A. Yes, they could.

12 Q. Are you aware that the company analyzes its
13 capacity resource mix as part of its annual and triennial
14 IRP processes?

15 A. I -- not in any great detail.

16 Q. Okay. But you're aware that the resources
17 actually procured by the company are solicited, evaluated,
18 and selected via a competitive RFP process?

19 A. Yes.

20 Q. Okay. And the evaluation criteria are set
21 forth in advance in each relevant RFP; right?

22 A. That's right.

23 Q. And Georgia Power has never relied on the IFR
24 adjustment as a reason to procure more natural gas
25 resources; correct?

1 A. Right.

2 Q. Okay. Beginning on page 12 of your
3 testimony, you discuss the relative proportion of natural
4 gas in Georgia Power's energy mix; correct?

5 A. Yes.

6 Q. Now, Figure 4 on page 13 outlines the annual
7 energy mix over time for the Southern Company energy
8 transition; correct?

9 A. Yes.

10 Q. And this was taken from a September 2024
11 Southern Company fact sheet; is that right?

12 A. Yes.

13 Q. Okay. But you're aware that this is Southern
14 Company system data and not Georgia Power specific; right?

15 A. I am.

16 Q. Okay. And as shown in Figure 4, the
17 percentage of coal in the energy mix has significantly
18 dropped from 69 percent in 2007 to 17 percent in 2003
19 [sic]; right?

20 A. Yes.

21 Q. And by using a chart that ends in 2003 [sic],
22 this graphic does not include the energy contribution of
23 Vogtle Unit 4; correct?

24 A. Right.

25 Q. And you'd agree that the contribution of

1 renewable energy has also grown between 2007 and 2023;
2 correct?

3 A. Yes.

4 Q. Did you happen to search for a Georgia-Power
5 specific energy mix?

6 A. I did.

7 Q. Okay. Did you find one?

8 A. It didn't cover a long enough period of time
9 that -- that I felt would be representative of a trend.

10 Q. Okay. So you were just looking for trends?

11 You weren't actually looking for updated
12 information on the actual balance that Georgia Power has
13 in its energy mix?

14 A. Well, I was looking for both.

15 Q. Okay. Did you happen to see the facts and
16 figures available on Georgia Power's website that includes
17 its energy mix?

18 A. I do recall seeing that, but I did not see
19 any history over time. It was a snapshot, I believe, of
20 the prior year.

21 Q. Are you aware that Georgia Power includes
22 that information in each of its IRPs?

23 A. Yes.

24 Q. Okay. And would it surprise you that Georgia
25 Power's energy mix is only made up -- as of 2024, is only

1 made up of 40 percent natural gas?

2 A. No, that does not surprise me.

3 Q. And that is different than the 52 percent
4 represented in the graphic in your testimony?

5 A. That's true.

6 Q. Are you aware that each month Georgia Power
7 files with the Commission an over-, under-recovery status
8 of the fuel balance?

9 A. I only learned that in the rebuttal
10 testimony.

11 Q. Okay. So you're not aware, then, that the
12 monthly filing includes actual fuel revenues and fuel
13 costs, as well as the projection of the FCR recovery
14 balance and the date -- all the way to the date of the
15 next fuel case?

16 A. Yeah. Are you referring to the 3382U?

17 Q. Yes.

18 A. Yes. So upon learning about that, I find
19 that you cannot even go on the Commission website and find
20 3382U in the search for a docket section. You can't even
21 find that particular set of reports, even if you just put
22 in 3382 and get a whole bunch of responses. And when you
23 do finally see it, it's heavily redacted and doesn't
24 really tell any of the details for the last three months,
25 if I recall, of what the actual fuel costs were, even

1 though they were filed monthly.

2 So I don't see how that series of reports is
3 useful to anyone. In fact, I'd love to know if the
4 Commission even really sees and reads all of it in detail,
5 because I find it incredibly hard to find or even know
6 that it exists.

7 Q. So were you here for the direct testimony of
8 Georgia Power's panel this morning?

9 A. Only a part of it.

10 Q. Okay. Did you -- did you happen to hear that
11 the actuals are updated quarterly?

12 So some of that redacted information you were
13 just describing is actually updated quarterly after it's
14 become public?

15 A. Yes, I did hear that.

16 Q. Okay. And are you aware when Georgia Power
17 makes a public -- a filing with the Commission that is
18 protected under trade secret protections, the public
19 disclosure version is what's included on the -- on the
20 docket, but that -- that does not mean that that's what's
21 limited to what staff reviews?

22 A. No, I didn't know that, but...

23 Q. Okay. You previously answered a couple
24 questions about adding a line item on customer bills. And
25 are you aware that -- I believe the answer is yes.

1 But are you aware that Georgia Power's retail
2 customers can request a detailed bill today?

3 A. Yes. I have heard that that -- I mean,
4 that's in the testimony. So I assume that that is
5 possible.

6 Q. Okay. Are you aware of any customers who've
7 made that request?

8 A. Yes. They had to finally call. It was not
9 possible through the electronic billing or the website or
10 Georgia Power's own -- own website under the section fuel
11 cost. There's no ability to do it without calling, as far
12 as I know.

13 Q. But once requested, the detailed bill does
14 include a line item for fuel cost; that's correct?

15 A. I believe so, yes.

16 Q. Okay. And it's typical for customers to have
17 to opt in to certain things when they work with their
18 utility?

19 For example, paperless billing. You'd have
20 to opt in to that, as well, too?

21 A. Yes. Opting in for paperless billing was
22 very easy, but you cannot do it for fuel costs. So I just
23 think if something is averaging 27 percent of the fuel
24 bill, it probably shouldn't -- it should be more of an opt
25 out. It should be included because it's such a large

1 percentage of the bill. And that's my point.

2 Q. Exhibit AL-2 to your testimony includes the
3 testimony of Jeremy Kalin and Brent Alderfer from FCR-26;
4 correct?

5 A. (No verbal response was given.)

6 Q. And you do not base any opinion or
7 recommendation in your testimony on their prior testimony;
8 correct?

9 A. That's correct.

10 Q. And are you aware that Mr. Kalin is also
11 participating in this case?

12 A. I do know that.

13 Q. And are you aware that he has recycled many
14 of his same arguments from his testimony he previously
15 gave that were not adopted or incorporated by this
16 Commission?

17 A. I assumed as much, yes.

18 Q. Okay.

19 A. I've read his testimony.

20 MS. PRYOR: Thank you. No further questions.

21 CHAIRMAN SHAW: Redirect.

22 MR. KAMANI: No redirect.

23 Mr. Chairman, I request Mr. Lin to be excused
24 and that GIPL-SF Exhibits 17, 18, and 19 be
25 admitted into evidence.

1 CHAIRMAN SHAW: So marked.

2 (GIPL/Southface Exhibits 17, 18, and 19 were
3 admitted into evidence.)

4 CHAIRMAN SHAW: Mr. Lin, thank you. Good to
5 see you again.

6 MR. LIN: Good to see you.

7 CHAIRMAN SHAW: You're excused.

8 MR. LIN: Thank you.

9 CHAIRMAN SHAW: And we're going to take just
10 a quick break while everyone's getting ready for
11 the next panel. So we'll go ahead and -- are you
12 ready?

13 (A recess was held from 5:14 p.m. until 5:18 p.m.)

14 CHAIRMAN SHAW: Ms. Isabella, are you ready?

15 MS. ARIZA: Thank you.

16 Chairman Shaw, may I swear in the witnesses?

17 CHAIRMAN SHAW: Yes, please.

18 MS. ARIZA: Could you each please raise your
19 right hand.

20 Thereupon,

21 JEREMY KALIN,
22 MICHAEL GOGGIN,
23 having been duly sworn, testified as follows:

24 MS. ARIZA: Thank you. You may take a seat.

25 DIRECT EXAMINATION

1 BY MS. ARIZA:

2 Q. We'll go in alphabetical order. Mr. Goggin,
3 please state your name, employer and responsibilities for
4 the record.

5 A. (Witness Goggin) My name is Michael Goggin.
6 I'm the executive vice president at Grid Strategies.

7 Q. Thank you.

8 Mr. Kalin, please state your name, employer,
9 and responsibilities for the record.

10 A. (Witness Kalin) I am Jeremy Kalin. I am a
11 partner and attorney at Avisen Legal in Minneapolis,
12 Minnesota.

13 Q. Thank you.

14 Mr. Goggin, on April 9, did you file or cause
15 to be filed 23 pages of public disclosure direct testimony
16 in Q&A format and seven exhibits?

17 A. (Witness Goggin) Yes.

18 Q. Are there any corrections you'd like to make
19 to either your exhibit or -- your exhibits or your
20 testimony?

21 A. (Witness Goggin) Yes. One set. After you
22 consulted with the company's counsel, company counsel
23 agreed to remove the trade secret designation regarding
24 the \$152 million of disallowance I'm recommending.

25 So that appears at page 2, lines 1 and 20;

1 page 9, line 13; and page 12, line 7 of my direct
2 testimony. So those would be now public, instead of trade
3 secret.

4 Q. Other than those corrections, if I were to
5 ask you the same questions today under oath, would your
6 answers be the same?

7 A. (Witness Goggin) Yes.

8 Q. Thank you.

9 Mr. Kalin, on April 9, did you file or cause
10 to be filed 34 pages of public disclosure direct testimony
11 in a Q&A format in this case and two exhibits?

12 A. (Witness Kalin) Yes.

13 Q. Are there any corrections you'd like to make
14 to either your testimony or your exhibits?

15 A. There are two. One is -- apologies for the
16 lack of pagination -- or of -- of line enumeration. So
17 we'll do our best for any references that might come up.
18 And the second is on page 5, line 6, 200 percent is more
19 accurately 267.2 percent, as reflected elsewhere in my
20 testimony.

21 Q. Other than that correction, if I were to ask
22 you the same questions today under oath, would your
23 answers be the same?

24 A. (Witness Kalin) Yes, they would.

25 MS. ARIZA: Chairman Shaw, the court reporter

1 has been provided with a copy of Mr. Goggin's and
2 Mr. Kalin's corrected versions of their prefiled
3 testimony. And so I ask that their testimony be
4 entered into the record as if given orally here
5 today.

6 CHAIRMAN SHAW: So marked.

7 (Whereupon, the prefiled direct testimonies
8 of Michael Goggin and Jeremy Kalin follows:)

**BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION**

In Re:

**GEORGIA POWER'S FUEL COST
RECOVERY (FCR-27) APPLICATION**

)
)
)

Docket No. 56765

**PUBLIC DISCLOSURE
DIRECT TESTIMONY
AND EXHIBITS
OF
MICHAEL S. GOGGIN**

**On Behalf of the
Southern Alliance for Clean Energy,
Sierra Club,
and Natural Resources Defense Council**

April 9, 2026

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1 **1. Introduction**

2 **Q. PLEASE STATE YOUR NAME AND JOB TITLE.**

3 **A.** My name is Michael S. Goggin, and I am the Executive Vice President at Grid Strategies,
4 LLC, a consulting firm based in the Washington, DC, area.

5 **Q. HAVE YOU PROVIDED AN EXHIBIT SUMMARIZING YOUR EDUCATIONAL**
6 **BACKGROUND AND PROFESSIONAL EXPERIENCE?**

7 **A.** Yes. It is presented in Exhibit MG-1. This exhibit summarizes my relevant experience and
8 qualifications.

9 **Q. ON WHOSE BEHALF ARE YOU APPEARING?**

10 **A.** I am testifying on behalf of the Southern Alliance for Clean Energy, Sierra Club, and
11 Natural Resources Defense Council.

12 **Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC**
13 **SERVICE COMMISSION OR OTHER UTILITY REGULATORY BODIES?**

14 **A.** Yes. I have testified before the Georgia Public Service Commission (“GPSC” or
15 “Commission”) in the last five Georgia Power Integrated Resource Plan (“IRP”) cases,
16 which were the 2025 full IRP, 2023 IRP Update, and the full IRP filings in 2022, 2019,
17 and 2016. I have also testified before state utility commissions in Arizona, Colorado,
18 Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana,
19 Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia,
20 Washington, and Wisconsin, before the Federal Energy Regulatory Commission
21 (“FERC”), and before the U.S. House Energy and Commerce Committee’s Subcommittee
22 on Energy.

23 **Q. CAN YOU PLEASE OUTLINE YOUR TESTIMONY?**

24 My testimony first provides background on how economic dispatch efficiently determines
25 which power plant units operate by dispatching the lowest-cost resources first. That section
26 also explains how uneconomic dispatch, either due to designating higher-cost generators
27 as “must-run” resources or simply using inputs that excessively dispatch higher-cost
28 resources, results in excessive costs for Georgia Power (“the Company”) ratepayers.

1 The bulk of my testimony then presents analysis that identifies \$ [REDACTED] million of ratepayer
2 net losses to date (through the end of February 2026) during the three-year historical period
3 for which Georgia Power seeks recovery in this case, June 1, 2023 to May 31, 2026, due
4 to uneconomic dispatch of the Bowen and Scherer coal power plants. These losses occurred
5 because the Company uneconomically dispatched these units, even though the Company's
6 own data show lower-cost resources were available. These total ratepayer losses represent
7 net losses, after factoring in startup costs and other costs in the counterfactual case wherein
8 the unit was shut down and then restarted once system marginal costs were high enough to
9 economically justify its operation, instead of remaining online.

10 The next section of my testimony then reviews a variety of factors that could result in
11 uneconomic dispatch and recommends solutions to reduce or eliminate these causes of
12 uneconomic dispatch.

13 Finally, I review how the Company increasing its dependence on gas generation exposes
14 its ratepayers to excessive costs and risks. As a notable example, ratepayers incurred more
15 than \$ [REDACTED] million in gas fuel costs for the Company's combined cycle generators alone
16 during the two weeks of Winter Storm Fern, January 23-February 6, 2026. I recommend
17 solutions that would better protect ratepayers from those costs and risks than the
18 Company's proposal to expand financial hedges.

19 **Q. WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION?**

20 **A.** I respectfully recommend that the Commission disallow recovery of the \$ [REDACTED] million in
21 net losses that occurred because of imprudent dispatch decisions for the Company's coal
22 fleet. This will protect ratepayers from shouldering these imprudently incurred costs, and
23 more importantly will incentivize the Company to avoid uneconomic dispatch going
24 forward.

25 To reduce uneconomic dispatch going forward, the Commission should direct the
26 Company to remove persistent biases in inputs into the Company's commitment and
27 dispatch software that result in suboptimal dispatch. I also recommend that the Commission

direct the Company to not negotiate coal supply and transportation contracts that include penalties for failing to meet minimum fuel delivery requirements. As explained below, those contract terms can cause the Company to run those plants even when they are not economic, resulting in their excessive and costly operation. In future fuel cost recovery cases, the Commission should also review new or extended fuel supply or transportation contracts to ensure they do not include penalties associated with minimum fuel delivery requirements.

Finally, I recommend that the Commission implement a fuel cost sharing mechanism to incentivize the Company to more effectively manage gas price risk, and account for the risks of gas price volatility and uncertainty when weighing the prudence of the Company increasing its dependence on gas generation.

Q. ARE YOU SPONSORING ANY EXHIBITS FOR YOUR TESTIMONY?

A. Yes, I am sponsoring the following list of exhibits.

Exhibit	Name	Confidentiality
MG-1	Michael S. Goggin background and qualifications	Public
MG-2	Georgia Power's response to data request STF-PIA-2-3 - Attachment A	Trade Secret
MG-3	Georgia Power's response to data request STF-PIA-2-2 - Attachment	Trade Secret
MG-4	Georgia Power's response to data request STF-PIA-2-6 - Attachment	Trade Secret
MG-5	Georgia Power's response to data request STF-PIA-2-3 - Attachment C	Trade Secret
MG-6	Georgia Power's response to data request STF-PIA-1-13	Public
MG-7	Georgia Power's response to data request STF-PIA-1-3	Public

2. Background on economic dispatch

Q. HOW DO UTILITIES TYPICALLY CHOOSE WHICH POWER PLANTS TO OPERATE?

A. Utility generation dispatch is designed to ensure that a generating facility with the lowest

1 incremental cost of producing an additional megawatt-hour (MWh) of electricity, also
2 referred to as marginal cost or marginal production cost, is used first before a higher-cost
3 resource like a coal plant is dispatched, which minimizes ratepayer costs. Incrementally
4 more expensive generation is then dispatched until generation supply meets demand. A
5 power plant's marginal production cost includes its fuel cost and other variable operations
6 and maintenance ("O&M") costs that increase in proportion to the MWh generated at the
7 plant. Capital and other fixed costs do not factor into the decision about which power plants
8 are selected because those sunk costs are incurred regardless of whether the power plant
9 operates. As a result, wind and solar resources that have no fuel cost and minimal variable
10 O&M costs are typically dispatched first, generally followed by other resources with low
11 marginal production costs like hydropower and nuclear, and then the grid operator
12 progresses through the remaining available resources in order of increasing marginal
13 production cost. While coal units are increasingly expensive to maintain and operate,
14 whether a specific coal unit is the highest marginal cost resource in a given hour depends
15 upon the specific variable costs associated with running that unit relative to other resources'
16 variable costs. As noted above, the variable costs to dispatch a unit depends upon its
17 variable O&M costs, its efficiency or heat rate, and the price of fuel, which for gas and to
18 a lesser extent coal is driven by real-time supply and demand factors. Accordingly, some
19 natural gas combined cycle generators have a lower marginal production cost than some
20 coal plants, while gas combustion turbines are less efficient and therefore generally have a
21 higher marginal production cost.

22 **Q. HOW DOES UNECONOMIC DISPATCH SPECIFICALLY HARM**
23 **RATEPAYERS?**

24 **A.** My analysis indicates that the Company's coal units are routinely operating at a loss,
25 reflecting that their marginal cost of producing electricity is greater than that of other
26 resources that were available . This indicates that the cost for the coal unit to produce that
27 electricity is greater than the value of that electricity. Said another way, the Company
28 ratepayers would have saved money if the Company replaced the coal generation with

1 energy generated by another resource. This excess cost is passed on to the Company
2 ratepayers through the fuel rider, which is determined in this proceeding. This uneconomic
3 dispatch of coal also displaces generation from lower-cost resources like solar and
4 hydropower, and in some cases from lower-cost natural gas combined cycle generation.
5 The costs for ratepayers are particularly high when uneconomic dispatch results in the
6 curtailment of renewable generation, replacing a non-emitting and zero-marginal-cost
7 resource with costly coal generation. For solar resources under Power Purchase
8 Agreements with the Company, depending on the terms of those contracts, renewable
9 curtailment can even result in the Company having to compensate renewable power
10 producers for lost revenue, further increasing the cost of uneconomic dispatch to the
11 Company ratepayers. By displacing lower-cost and lower-emitting generation, uneconomic
12 coal dispatch also increases emissions of pollutants that harm public health and the
13 environment.

14 **Q. ARE VERTICALLY-INTEGRATED UTILITIES MORE LIKELY TO**
15 **UNECONOMICALLY DISPATCH THEIR GENERATION?**

16 **A.** Yes. In contrast to merchant generators whose profits are reduced by uneconomic
17 generation, fuel costs do not affect the profits of vertically integrated utilities like the
18 Company, which pass their fuel costs through to their ratepayers in proceedings such as
19 this one. Many analysts have found that vertically integrated utilities are much more likely
20 to uneconomically dispatch their coal plants than merchant plant owners because it does
21 not affect their profits.¹ Vertically integrated utilities' economic indifference to fuel costs
22 requires diligent regulation from state utility commissioners to protect ratepayers from

¹ See Catherine Morehouse, *MISO Integrated Utilities Lost \$492M From 2016-2019 Via Uneconomic Coal Dispatch: Market Monitor*, UTILITY DIVE (Oct. 9, 2020), <https://www.utilitydive.com/news/miso-integrated-utilities-lost-492m-from-2016-2019-via-uneconomic-coal-dis/586714/> (last visited July 15, 2025); JOE DANIEL ET AL., UNION OF CONCERNED SCIENTISTS, USED, BUT HOW USEFUL?: HOW ELECTRIC UTILITIES EXPLOIT LOOPHOLES, FORCING CUSTOMERS TO BAIL OUT UNECONOMIC COAL-FIRED POWER PLANTS (2020), <https://www.ucsusa.org/sites/default/files/2020-05/Used%20but%20How%20Useful%20May%202020.pdf>; RMI, *Economic Dispatch Dashboard*, UTILITY TRANSITION HUB, <https://utilitytransitionhub.rmi.org/economic-dispatch/> (last visited July 15, 2025).

imprudent commitment and dispatch decisions.

Q. WHAT IS A MUST-RUN DESIGNATION?

A. One form of uneconomic dispatch is a must-run designation. When a utility designates a unit as must-run, it elects to operate the unit regardless of economics. As a result, the unit will run even if it has a higher cost than the marginal resource that was selected through economic dispatch, which results in costs for ratepayers. There can be legitimate reasons for using a must-run designation, such as completing generator testing that requires a unit to operate, though in other cases must-run designations are not justified. As explained in the following section, our analysis conservatively excludes net ratepayer costs that were incurred during must-run designations, as the Company did not provide sufficient information to assess the prudence of those must-run designations.

3. Analysis Method and Results

Q. WHAT METHOD DID YOU USE FOR YOUR ANALYSIS?

A. For each hour to date in the three-year historical period for which Georgia Power is requesting rate recovery in this proceeding, June 1, 2023 to May 31, 2026, I assessed whether the marginal production cost of an operating coal unit² exceeded the Company's day-ahead forecast for system-wide marginal production cost, a metric that is also known as system "lambda."³ System lambda measures the marginal cost of the highest cost unit dispatched across the Company's system to meet electricity demand in an hour. The Company's coal units include four units totaling 3,498.6 MW nameplate capacity at Plant Bowen, and three units totaling 2,673 MW at Plant Scherer, for a total of 6,171.6 MW.⁴ The Company provided data through the end of February 2026 in response to discovery, so the analysis covers the period June 2023-February 2026, or approximately 2 and ¾

² See Company's Trade Secret Response to STF-PIA-2-3 Attachment A (providing hourly marginal production costs for the coal units).

³ See Company's Trade Secret Response to STF-PIA-2-2 Attachment.

⁴ Nameplate capacity taken from EIA, *Preliminary Monthly Electric Generator Inventory: January 2026*, <https://www.eia.gov/electricity/data/eia860m/>.

1 years.

2 In conducting this analysis, I used the Company's day-ahead forecast for system lambdas,
3 which varied depending on the incremental fuel costs and other incremental variable costs
4 of the resources the Company dispatched during those specific hours. If an operating coal
5 unit's marginal production cost exceeded the system lambda, this indicates that the unit
6 was uneconomic relative to other available resources, and thus the Company incurred a
7 loss by operating the unit in that hour. To calculate the net cost of the Company keeping a
8 coal unit online, for each must-run event, I also factored in the startup and shutdown costs
9 for the unit to calculate the cost of the alternative case of the unit shutting down and then
10 restarting once power prices were high enough for it to profitably operate.⁵ Put simply,
11 this counterfactual was intended to assess whether the costs associated with shutting off
12 and restarting a high marginal cost coal unit outweigh the value of power provided by a
13 lower marginal cost alternative resource. As a result, time periods in which a coal unit was
14 unprofitable, but shutting it down and restarting it would have resulted in higher net costs
15 to ratepayers, were not counted in our analysis as they did not impose a net cost on
16 ratepayers. I also incorporated the Company's reported coal unit operating constraints,
17 including startup time, minimum uptime, and minimum downtime when designing this
18 counterfactual.⁶ Accounting for these start up and shutdown costs and other operating
19 constraints reduced the number of periods that resulted in a net cost for purposes of this
20 case, as those dispatch decisions were arguably prudent for the Company's existing
21 generating fleet. However, the Commission should recognize that transitioning to a fleet
22 with more flexible resources, like battery storage, will reduce the need to unprofitably
23 operate inflexible coal resources.

⁵ See Company's Trade Secret Response to STF-PIA-2-6 Attachment.

⁶ *Id.*

1 **Q. WHY DID YOU COMPARE THE COAL UNIT'S COST AGAINST SYSTEM**
2 **LAMBDA?**

3 **A.** Because system lambda reflects the marginal cost of the highest cost unit dispatched across
4 the Company's system to meet electricity demand in that hour, it is the best metric of the
5 marginal cost of producing electricity in that hour. If the coal unit's cost is higher than
6 system lambda, this indicates that the lower-cost generator setting the system-wide lambda,
7 and in many cases other resources like imports, could have more economically provided
8 that generation than the coal unit.

9 **Q. WHY DID YOUR ANALYSIS USE THE DAY-AHEAD FORECAST FOR**
10 **LAMBDA INSTEAD OF REAL-TIME LAMBDA?**

11 **A.** In the day-ahead timeframe, the utility selects which resources are "committed" to operate
12 the next day, so the power plant operators can make any necessary preparations, like
13 starting up their units (for coal units) or procuring fuel (for gas units). Because coal plants
14 take a long time to start up and have limited flexibility, our analysis exclusively focused
15 on the day-ahead forecast for system lambda. This metric accurately reflects the supply
16 and demand balance and generator economics in the day-ahead timeframe when the
17 Company decided which power plants to commit to operate so that long startup time coal
18 units could be online by the next day. This makes our analysis conservative, as it does not
19 penalize the Company when there were unexpected drops in electricity demand or
20 increases in supply after the day-ahead timeframe when it committed the coal units. Said
21 another way, this ensures the analysis is not "Monday morning quarterbacking" with the
22 advantage of perfect hindsight, and instead is only judging the Company's commitment
23 decisions based on the information that was available to the Company at the time it made
24 those decisions.

25 Georgia Power is the operator for all units at Scherer,⁷ even though the units are jointly
26 owned with other utilities, so Georgia Power is responsible for commitment and dispatch

⁷ For example, see Oglethorpe Power Corporation, *SEC Form 10-K for 2024* at 5,

1 decisions for these units. The results presented below allocate total net costs from
2 uneconomic dispatch to Georgia Power in proportion to Georgia Power's ownership of
3 each unit, so the results below accurately reflect the costs that are passed through to
4 Georgia Power ratepayers.

5 **Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS?**

6 **A.** The charts and table below report all uneconomic dispatch events that resulted in a net cost
7 to ratepayers. Figure 1 sums the total net cost of uneconomic dispatch by unit, breaking out
8 the share of uneconomic dispatch costs that occurred in periods with must-run designations
9 versus other factors, while Table 1 reports the same information in tabular form. These net
10 costs total \$[REDACTED] million over the period June 2023-February 2026, of which \$[REDACTED] million
11 were incurred during time periods that included must-run designations. For reference, the
12 Company's filing shows \$[REDACTED] billion in total costs for coal generation over the 2 year
13 and 7 month period of June 2023-December 2025.⁸ The \$[REDACTED] million in imprudently
14 incurred costs over the 2 year 9 month period of our analysis were around [REDACTED]% of the
15 Company's total coal fuel costs over the reported 2 year 7 month period (the percentage
16 would be slightly lower than [REDACTED]% if the additional two months of total fuel costs were added
17 to the denominator).

18
19
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23

<https://www.sec.gov/Archives/edgar/data/788816/000162828025015552/opc-20241231.htm>; Deloitte, *Independent Auditors Report: Gulf Power*, at 12 (59 in pdf) <https://www.investor.nexteraenergy.com/~media/Files/N/NEE-IR/fixed-income-investors/download-library/gulf-power/gulf-taxexemp-oct2019.pdf>.

⁸ Workpaper MFRH-2 TS.xlsx provided with Georgia Power's filing.

Figure/Table 1: Net cost of uneconomic dispatch June 2023-February 2026, by unit



	Uneconomic Dispatch	Must-run	Total
Bowen 1			
Bowen 2			
Bowen 3			
Bowen 4			
Scherer 1			
Scherer 2			
Scherer 3			
Total			

The Company's coal units operated at a net loss more than % of the time, with Bowen Units 3 and 4 and Scherer Unit 3 operating uneconomically of the time, as

shown in Table 2 below. This is calculated as a percent of the total hours when they were available for economic dispatch (*e.g.* not on outage or under a must-run designation) during the analysis period. If periods of uneconomic dispatch under must-run designations were included, these percentages would be even higher.

Table 2: Percent of total available hours during June 2023-February 2026 in which each unit operated at a net loss

Unit	% of available hours in which unit operated at a net loss
Bowen 1	
Bowen 2	
Bowen 3	
Bowen 4	
Scherer 1	
Scherer 2	
Scherer 3	
Average	

Q. WHAT FACTORS DID THE COMPANY CITE FOR CAUSING ITS USE OF MUST-RUN DESIGNATIONS?

A. In response to discovery, the Company indicated days when each coal unit was designated as a must-run unit, as well as the Company's stated reason for making that designation.⁹ The Company's stated reason for all must-run designations was [REDACTED]. The Company's pre-filed direct testimony also explains that the "FCR-27 budget includes must-run requirements for Plant Bowen to address system constraints and ensure operational reliability."¹⁰

⁹ See Company's Trade Secret Response to STF-PIA-2-3 Attachment C.

¹⁰ Direct Testimony of Mr. Houston and Mr. Berrigan, at 17.

1 **Q. WERE THESE USES OF MUST-RUN DESIGNATIONS JUSTIFIED AND**
2 **PRUDENT?**

3 **A.** It is not clear. The Company did not provide adequate information about its commitment
4 and dispatch model processes and results to assess the extent to which the must-run
5 commitments of coal units were prudent. To be conservative, we have excluded
6 uneconomic dispatch costs incurred during must-run designations from our analysis. As a
7 result, the recommended disallowance is \$[REDACTED] million. If net costs incurred during must-
8 run designations were included, the recommended total disallowance would increase by
9 \$[REDACTED] million to \$[REDACTED] million, as shown in Figure 1 and Table 1 above.

10 **Q. DO THESE MUST-RUN COMMITMENTS INDICATE OTHER SOLUTIONS**
11 **ARE NEEDED TO REDUCE THEIR USE GOING FORWARD?**

12 **A.** Yes. Because the Company claims the must-run commitments were due to [REDACTED]
13 [REDACTED]
14 [REDACTED]. As I have explained in the Company's IRP
15 proceedings, ratepayers would benefit from a proactive multi-value transmission planning
16 process that uses tools like production cost modeling to account for the economic value
17 of transmission reducing congestion.¹¹ [REDACTED]

18 [REDACTED]
19 [REDACTED]
20 [REDACTED]
21 [REDACTED]
22 [REDACTED]

23 **Q. HOW DO FUEL COSTS AFFECT UNECONOMIC DISPATCH?**

24 **A.** Fuel costs are the largest component of total marginal production costs, with plant variable
25 O&M costs generally being much smaller. Energy Information Administration data show

¹¹ For example, see the Direct Testimony of Michael Goggin in Docket No. 56002, Georgia Power Company's 2025 Integrated Resource Plan, <https://services.psc.ga.gov/api/v1/External/Public/Get/Document/DownloadFile/222515/103630>, at 14-38.

1 that Plant Bowen has an average coal price that is significantly higher than Plant Scherer's,
2 and the national average. Specifically, Plant Bowen's average coal price in 2025 was \$3.96
3 per million British thermal units ("MMBtu"), while Scherer's was \$3.02 per MMBtu,¹² and
4 the national average coal price was \$2.55 per MMBtu in 2024.¹³ Plant Bowen is fueled by
5 Appalachian and Illinois Basin coal, which is significantly more expensive to produce than
6 the Powder River Basin coal used by most coal power plants. In response to discovery,
7 Georgia Power indicates that:

8 The Company explored switching Plant Bowen over the years and the various
9 studies have shown that converting the coal units at Plant Bowen to be able to burn
10 PRB [Powder River Basin] coals would require a large amount of capital
11 investment. In addition, even though the PRB coal is cheaper than Appalachian and
12 IB [Illinois Basin] coal on average per ton basis, there is a capacity reduction
13 associated with PRB in comparison due to lower coal quality of subbituminous
14 coal. Given the significant capital investment required and the lower expected
15 capacity output with PRB coal, the switching of Plant Bowen to PRB coal would
16 be uneconomic for customers.¹⁴

17 The fuel cost figures for Bowen and Scherer in the preceding paragraph are presented in
18 \$/MMBtu, so they account for differences in the energy content of different types of coal.
19 The Company did not provide any studies in this docket supporting the conclusion that
20 retrofit costs would outweigh fuel cost savings. In separate proceedings, the Company and
21 the Commission should assess whether Bowen should be retired due to its high fuel costs
22 and other factors.

¹² EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920): 2025*, https://www.eia.gov/electricity/data/eia923/xls/t923_2025.zip, page 5, multiplying price times quantity for each coal purchase, and then summing the total cost and dividing by the total quantity for all purchases.

¹³ Electric Power Annual 2024, Table 7.5, <https://www.eia.gov/electricity/annual/pdf/epa.pdf>. During the first nine months of 2025, generators paid an average of \$2.43/MMBtu for coal, per *U.S. coal-fired generators reprieved by higher gas prices*, <https://jkempenergy.com/2025/12/11/u-s-coal-fired-generators-reprieved-by-higher-gas-prices/>.

¹⁴ Company response to STF-PIA-1-13.

1 In this proceeding, however, the Commission can disallow costs that were imprudently
2 incurred from the excessive operation of Plant Bowen. The results above indicate that the
3 Company routinely committed and operated Plant Bowen when its generation was not
4 needed and lower-cost sources of generation were available.

5 **4. Dissecting the factors that drive uneconomic dispatch**

6 **Q. WHAT FACTORS CAN CAUSE UNECONOMIC DISPATCH?**

7 **A.** As shown in Table 1 above, factors that cause uneconomic dispatch can generally be
8 grouped into a utility designating a unit as must-run, and other factors that result in a flawed
9 and uneconomic dispatch outcome. These other factors can include flaws in the generator
10 commitment and dispatch process, including systemic biases in forecasts used in that
11 process, inefficient fuel contract structures, and other factors. This section reviews those
12 factors in more detail and develops recommendations for the Commission to address these
13 problems.

14 **Q. ARE THERE FLAWS IN GEORGIA POWER'S COMMITMENT PROCESS?**

15 **A.** Yes. Persistent biases or other flaws in the inputs into the generator commitment process
16 can increase ratepayer costs by inefficiently overcommitting generators. In response to
17 discovery, the Company provided¹⁵ data allowing a comparison between its actual load
18 data and its day-ahead load forecast, and between actual solar output and its day-ahead
19 solar forecast. Over the three year period, the day-ahead load forecast [REDACTED]
20 [REDACTED]. The Company's solar forecast [REDACTED]
21 [REDACTED] MW on average. Taken together, these persistent biases result in a [REDACTED]
22 [REDACTED] of the need for conventional generation. A statistical t-test¹⁶ confirms that an
23 over-forecasting bias of this size exceeds the deviation expected due to normal forecast
24 error by many orders of magnitude. This persistent and significant overestimate of need
25 contributes to the overcommitment of coal units, which results in uneconomic dispatch of

¹⁵ See Company's Trade Secret Response to STF-PIA-2-2 Attachment.

¹⁶ A statistical t-test compares the averages between two sampled groups to determine whether the variance in those averages is statistically significant.

those coal units to the detriment of ratepayers. The Commission should also recognize that transitioning to a fleet with more flexible resources that can quickly start up and respond to changes in supply and demand, like battery storage, will eliminate costs caused by day-ahead forecast errors.

Q. WHAT OTHER FACTORS CAN CAUSE UNECONOMIC DISPATCH?

A. Utilities can also uneconomically over-dispatch coal plants to use up surplus coal supplies to avoid penalties associated with minimum delivery requirements in coal transportation contracts. This factor was not accounted for in our analysis, as our analysis conservatively used the marginal fuel costs as provided by the Company in discovery without questioning their accuracy or reasonableness. As a result, our analysis likely significantly understates the full ratepayer costs of uneconomic dispatch.

The Company explains that it reduces the assumed marginal fuel cost for coal generators in its generator commitment and dispatch decisions to account for these penalties, if the Company is falling below the minimum delivery requirement:

If the applicable transportation contract contains minimum-volume / take-or-pay provisions with liquidated damages (or similar shortfall charges), the marginal replacement cost of transportation component reflects those provisions only to the extent they affect the incremental cost of additional deliveries based on the timing of need:

- i.* When forecast deliveries are below the contractual minimum, the component of transportation costs covered by the shortfall/liquidated damages is treated as fixed and excluded from the marginal replacement cost for incremental deliveries up to the minimum;...¹⁷

By reducing the fuel cost that is the primary component of the marginal production cost for coal generators, accounting for these penalties makes it much more likely for coal units

¹⁷ See Company's Response to STF-PIA-1-3.

1 to operate. While this is the economically rational response to avoid those penalties, which
2 is why our analysis conservatively does not contest the Company's assumed fuel costs,
3 contracts that include those penalties are economically inefficient as they incentivize
4 Georgia Power to excessively operate coal plants to consume more coal. The Commission
5 can ensure that this type of uneconomic dispatch does not occur in the future by requiring
6 the Company to move to more efficiently structured contracts for coal transportation that
7 do not include such penalties as new fuel contracts are signed or existing contracts come
8 up for renewal. The Commission should also recognize that transitioning to a fleet that is
9 less dependent on inflexible fuel contracts will reduce the cost of these penalties.

10 **Q. WHAT STRUCTURE DOES AN ECONOMICALLY EFFICIENT FUEL**
11 **CONTRACT USE INSTEAD OF PENALTIES FOR FAILING TO MEET**
12 **MINIMUM DELIVERY QUANTITIES?**

13 **A.** In an economically efficient fuel contract, the price the Company pays for each ton of
14 delivered coal should only include the marginal cost of extracting and delivering that fuel.
15 While the coal mine operator or railroad does have fixed costs associated with building and
16 operating the infrastructure necessary to produce and deliver the coal, those fixed costs
17 should be recovered separately from the variable per-unit price of the fuel. Capital and
18 other fixed costs associated with that infrastructure should be recovered as fixed costs in
19 the fuel supply contract, such as through a one-time payment or a fixed cost per year. Fuel
20 contracts that use minimum delivery requirements and penalties to recover fixed costs are
21 inherently inefficient as these fixed costs should not affect the marginal cost of the fuel.

22 **5. Gas price risk**

23 **Q. Is gas price volatility a major risk for the Company ratepayers?**

24 **A.** Yes. Henry Hub natural gas prices have increased by around 50% over the last year and a
25 half.¹⁸ Natural gas prices are volatile and uncertain on both a day-to-day basis due to

¹⁸ EIA, *Henry Hub Natural Gas Spot Price (Dollars per Million Btu)*,
<https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm>.

1 weather, and on a longer-term basis due to economic and geopolitical factors. Increased
2 U.S. exports of Liquefied Natural Gas (LNG) have increasingly tethered domestic gas
3 prices to the global price for gas, which is higher and heavily affected by geopolitical
4 volatility and uncertainty. For example, Russia's invasion of Ukraine and the ongoing
5 closure of the Strait of Hormuz have caused global natural gas prices to increase
6 dramatically, and to display greater volatility and uncertainty. The linkage between
7 domestic and global natural gas prices is likely to increase as the U.S. is expected to roughly
8 double its LNG export capacity by 2029, after increasing from essentially nothing to 15.4
9 billion cubic feet per day (bcf/day) over the last decade,¹⁹ an amount that is comparable to
10 nearly 17% of U.S. gas consumption in 2025.²⁰

11 Moreover, ongoing consolidation in the gas supply and transportation industries may result
12 in higher and more volatile gas prices. Ernst and Young reports that oil and gas industry
13 "[m]erger and acquisition expenditures increased 331% in 2024, from US\$47.9 billion in
14 2023, to US\$206.6 billion in 2024."²¹ For example, the largest gas producer in the
15 Appalachian basin has recently completed acquisitions and announced plans to increase
16 prices by reducing production.²²

17 **Q. HOW HAVE EXTREME COLD WEATHER EVENTS AFFECTED GAS PRICES?**

18 **A.** Delivered gas prices also show major volatility and uncertainty on a short-term basis,

¹⁹ EIA, *North America's LNG export capacity could more than double by 2029*, (October 16, 2025), <https://www.eia.gov/todayinenergy/detail.php?id=66384>.

²⁰ EIA, *U.S. natural gas consumption set a monthly and yearly record in 2025*, (March 18, 2026) <https://www.eia.gov/todayinenergy/detail.php?id=67365#>.

²¹ Ernst and Young, *US oil and gas reserves, production and ESG benchmarking study*, <https://www.ey.com/content/dam/ey-unified-site/ey-com/en-us/industries/oil-gas/documents/ey-us-oil-and-gas-reserves-production-esg-study-2025-final.pdf> at 6.

²² For example, see EQT, *EQT Announces Strategic Production Curtailment*, (March 2024) <https://ir.eqt.com/investor-relations/news/news-release-details/2024/EQT-Announces-Strategic-Production-Curtailment/default.aspx>; N. Cano, *EQT's Q2 Call Highlights Strategic Shift Toward Demand-Linked Growth*, (July 2025) <https://aegis-hedging.com/insights/eqts-q2-call-highlights-strategic-shift-toward-demand-linked-growth>; Reuters, *EQT to buy Olympus Energy assets for \$1.8 bln to boost Marcellus presence*, (April 2025) <https://www.reuters.com/business/energy/eqt-acquire-upstream-midstream-assets-olympus-energy-18-billion-2025-04-22/>.

1 primarily due to weather events that increase demand and/or affect supply. Cold weather
2 events have the largest impact because they cause a spike in natural gas use for building
3 heating, just as demand for electricity generation also increases. Because of the strong
4 positive correlation between gas demand for building heating and electricity generation
5 during winter, there are likely to be larger price spikes during extreme cold as more gas is
6 used for electricity generation, including Georgia Power's ongoing and proposed
7 expansion of gas generation.

8 Extreme cold events can also disrupt supplies of gas by causing gas wellheads to freeze,
9 just as gas demand peaks. Pipeline constraints during periods of high demand can also
10 cause price spikes or even shortages. Winter Storms Uri, Elliott, and Fern caused dramatic
11 spikes in the price of natural gas in the Eastern U.S due to wellhead freezeoffs. For
12 example, PJM notes that during Winter Storm Fern, there was a 10 billion cubic feet/day
13 drop in natural gas production nationally due to frozen gas wells.²³ This is smaller than the
14 well freeze-offs during both Uri and Elliott, when gas production dropped by around 20
15 percent nationally, or 20 billion cubic feet/day.²⁴ While gas supply interruptions during
16 Fern were not large enough to repeat the rolling blackouts that occurred during Uri and
17 Elliott, ratepayers were not spared an economic hit. PJM notes that "Spot gas prices
18 through this event reached historic levels throughout the eastern U.S. with many hubs
19 trading well over \$100/mmbtu with prices in NY and New England approaching
20 \$300/mmbtu."²⁵

21 Shortfalls in gas supply due to wellhead freezeoffs, along with generator equipment failures
22 and pipelines equipment outages and constraints, contributed to widespread correlated
23 outages of gas generators during recent extreme cold weather events. FERC and NERC
24 reports and regional analyses have documented that forced outages and derates of gas

²³ PJM, *January Cold Weather Operations*, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2026/20260205/20260205-item-03---cold-weather-update.pdf>, at 38.

²⁴ *Id.* at 40.

²⁵ *Id.* at 38.

generators were the primary cause of electric reliability problems during recent extreme cold weather events, including Winter Storm Elliott,²⁶ Winter Storm Uri,²⁷ the 2018 Bomb Cyclone,²⁸ the 2018 South Central Cold Snap,²⁹ and the 2014 Polar Vortex.³⁰ In particular, gas accounted for 63% of unplanned outages and derates during Winter Storm Elliott, and 55% during Winter Storm Uri and the 2014 Polar Vortex, while coal accounted for a large share of the remainder.

Q. HOW DID THE SPIKE IN GAS PRICES DURING WINTER STORM FERN AFFECT GEORGIA POWER'S RATEPAYERS?

A. [REDACTED] Georgia Power's response to STF-PIA 2-3 Attachment A Trade Secret shows \$ [REDACTED] million in fuel expenditures for Georgia Power's gas combined cycle generators alone over the two week period from January 23-February 6, 2026. This translates into an average fuel cost of \$ [REDACTED]/MWh, which for the average heat rate for the McDonough and McIntosh combined cycle generators in January 2025 of 6.920 MMBtu/MWh³¹ reflects a gas fuel cost of \$ [REDACTED]/MMBtu, or [REDACTED] times the \$3.52 Henry Hub average in 2025.³² The fuel cost

²⁶ FERC and NERC, *December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations*, (September 21, 2023), <https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott>, at 5.

²⁷ FERC and NERC, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (2021), <https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and>, at 16.

²⁸ U.S. Energy Info. Admin., *January's Cold Weather Affects Electricity Generation Mix in Northeast, Mid-Atlantic* (Jan. 23, 2018), <https://www.eia.gov/todayinenergy/detail.php?id=34632>.

²⁹ FERC and NERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*, (July 2019), https://www.nerc.com/pa/rm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf, at 57-58, 96-97.

³⁰ NERC, *Polar Vortex Review iii* (Sept. 2014), https://www.nerc.com/globalassets/our-work/reports/event-reports/polar_vortex_review_29_sept_2014_final.pdf, at 13.

³¹ EIA, *Form EIA-923 detailed data with previous form data: 2025*, https://www.eia.gov/electricity/data/eia923/xls/f923_2025.zip page 5 (dividing total MMBtu of fuel consumed by MWh generated for those two plants for January 2025).

³² EIA, *Henry Hub Natural Gas Spot Price*, <https://www.eia.gov/dnav/ng/hist/mgwhhdA.htm>.

1 identified above only accounts for combined cycle generation, which includes 4,141.4 MW
2 of owned capacity and the 230 MW Santa Rosa PPA for a total of 4,371 MW. Georgia
3 Power also owns 1,618.4 MW of other gas generating capacity, which have a significantly
4 worse average heat rate, so we can roughly estimate that the total gas fuel cost for Georgia
5 Power ratepayers during Winter Storm Fern exceeded \$ [REDACTED] million. For reference, the fuel
6 cost for the 4,141.4 MW of combined cycle generators owned by Georgia Power over the
7 2 year 7 month period covered in the Company's filing totaled \$ [REDACTED], so the \$ [REDACTED]
8 million cost during the two week period of Winter Storm Fern was more than [REDACTED] % of the
9 cost incurred over the preceding 134 weeks.³³

10 **Q. ARE THE COMPANY'S PROPOSALS TO EXPAND ITS USE OF FINANCIAL**
11 **HEDGING ADEQUATE TO MITIGATE THIS RISK.**

12 **A.** No. First, the Company has not proposed to fully cover its gas needs via hedges or long-
13 term contracts. More importantly, it is difficult for financial institutions to hedge their
14 price risk for commodities like natural gas, which has large and widespread price
15 volatility and uncertainty due to the factors discussed above, including highly correlated
16 risks in gas supply and transportation. A financial institution is willing to sell me health
17 insurance or homeowners insurance at a reasonable price because the odds of me
18 becoming ill or my house burning down are not highly positively correlated with the risk
19 of those things happening to other people at the same. However, gas deliveries regionally
20 and even nationally are dependent on a small number of supply fields and pipelines,
21 which as documented above are prone to disruption, particularly during extreme cold
22 events that also cause gas demand to spike. As a result, a counterparty offering Georgia
23 Power a hedge cannot adequately hedge that risk itself. The result is that financial
24 hedging products will come at a significant price premium or will not adequately cover
25 risks, and those costs and risk will be passed on to Georgia Power ratepayers. For
26 example, Georgia Power's filing in this proceeding shows \$ [REDACTED] million in net costs for

³³ Workpaper MFRH-2 TS.xlsx provided with Georgia Power's filing.

1 natural gas hedges over the period 2023-2025, or more than \$■ million per year on
2 average.³⁴

3 **Q. HOW CAN THE COMMISSION REDUCE RATEPAYERS' EXPOSURE TO**
4 **THAT RISK?**

5 **A.** As an initial step, the Commission should require the Company to adopt a fuel cost sharing
6 mechanism. Fuel cost sharing mechanisms incentivize utilities to reduce their exposure to
7 gas price volatility, in turn reducing ratepayers' exposure to that risk. Fuel cost sharing
8 mechanisms are particularly important for incentivizing Georgia Power to make prudent
9 decisions regarding meeting new load with new fuel-based generation or non-fuel-based
10 resources.

11 Fuel cost sharing mechanisms address a type of market failure economists term a "moral
12 hazard," namely the principal-agent problem. There is a market failure because the
13 Company does not bear the cost or risk of the decisions it makes regarding whether to
14 increase its dependence on gas generation and what physical mechanisms to use to reduce
15 that risk, which can significantly increase costs for ratepayers. Said another way, the
16 Company is the agent who makes the decision, but the ratepayer is the principal who pays
17 the cost of that decision. The solution to a principal-agent problem is to internalize the
18 cost and risk of a decision to the agent making the decision, which in this case is the
19 Company.

20 **Q. WHAT CAN THE COMPANY DO TO MITIGATE GAS PRICE RISK?**

21 **A.** Several things. In situations like this where financial hedges are unable to adequately
22 mitigate correlated risks, a primary solution is for Georgia Power and the Commission to
23 make generation mix choices that create a physical hedge. A fuel cost sharing mechanism
24 will incentivize Georgia Power to account for the price risk of natural gas when making
25 decisions about the optimal generation mix should. The Company can also pay for steps
26 that somewhat improve the availability of gas, like increasing access to gas storage or

³⁴ *Id.*

1 buying firm transportation. However, these steps do not fully mitigate the economic or
2 reliability risk of gas generation. For example, firm transportation does not fully address
3 the risks from supply freezeoff events discussed above. Firm transportation customers are
4 still subject to *force majeure* declarations by the pipeline in the event of pipeline failures
5 or constraints due to supply shortfalls. Gas storage is also subject to failures itself,
6 deliveries of gas from storage can be affected by pipeline interruptions or constraints, and
7 the gas storage must be refilled using the same risky sources of supply.

8 The most resilient solution to a range of economic and reliability risks is diversifying the
9 Company's generation mix by adding resources like renewable and battery resources that
10 do not rely on volatily-priced fuel deliveries that can be interrupted by extreme weather or
11 other unexpected events. The Commission should thoroughly weigh the economic and
12 reliability risks for ratepayers from the Company increasing its dependence on gas
13 generation and fuel-based generation in general. Adding renewable, storage, and demand-
14 side resources builds a more diverse generation mix that reduces ratepayer risk and
15 increases resilience. Each resource type has distinct outage risks, so a diverse mix reduces
16 the economic and reliability risk to ratepayers. As the age-old aphorism explains, putting
17 all of your eggs in one basket is not a resilient strategy.

18 **6. Conclusion**

19 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

20 **A.** I respectfully recommend that the Commission disallow recovery of the \$152 million in
21 net ratepayer losses that occurred over the period June 2023-February 2026 as a result of
22 uneconomic coal unit dispatch. This represents about █% of the \$█ billion in total fuel
23 costs over the period June 2023-December 2025 for which the Company is seeking
24 recovery. This will protect ratepayers from shouldering these imprudently incurred costs,
25 and more importantly will incentivize the Company to not imprudently dispatch resources
26 going forward.

1 To that end, I further recommend that the Commission direct the Company to take prudent
2 and cost-effective steps to minimize or eliminate uneconomic dispatch going forward.
3 Specifically, the Commission should direct the Company to remove inefficient penalty
4 provisions from coal transportation contracts as existing contracts come up for renewal or
5 new contracts are signed and [REDACTED] and other flaws in the
6 economically optimized generator commitment and dispatch process that result in
7 suboptimal dispatch that increases ratepayer costs. The Commission should also
8 thoroughly weigh the net benefits of replacing uneconomic and inflexible coal resources
9 with more cost-effective modern resources, particularly renewable resources without fuel
10 price risk and flexible battery storage.

11 Finally, the Commission should require the Company to effectively manage gas price risk
12 through a fuel cost sharing mechanism. This will incentivize the Company to thoroughly
13 weigh the risks for ratepayers from increasing its dependence on gas generation relative to
14 renewable and battery resources that are not subject to volatile fuel prices.

15 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

16 **A.** Yes.
17
18
19
20
21
22
23

MG-1: Michael S. Goggin background and qualifications

Michael Goggin

Education:

Harvard University class of 2004, B.A. *cum laude* in Social Studies

- Wrote thesis “Is it Time for a Change? Science, Policy, and Climate Change”

Experience:

Grid Strategies Executive Vice President February 2018-present

- Serve as an expert consultant on electricity transmission, grid integration, reliability, market, and policy issues for non-profit, grid operator, state regulator, and industry clients
- Have testified before FERC and in dozens of state regulatory commission cases
- Actively engaged in NERC Standards development processes related to renewable and storage resources

AWEA Senior Director of Research, other titles February 2008-February 2018

- Led team responsible for all American Wind Energy Association analysis
- Served as primary technical and economic expert on market design, transmission, grid integration, carbon policy, and other topics
- Authored regulatory filings at state (IRP and transmission siting cases), regional (RTO transmission and market design), and federal levels (FERC transmission, interconnection standard, grid integration, and market design cases; EPA carbon policy)
- Directed economic and power sector modeling to inform AWEA’s policy strategy and support advocacy positions
- Communicated with the press and policy makers about wind energy
- Other titles included Electric Industry Analyst, Senior Analyst, Manager of Transmission Policy, Director of Research

Sentech, Inc. Research Analyst October 2005-February 2008

- Conducted economic analyses of solar, wind, geothermal, hydrogen, and energy storage technologies for U.S. Department of Energy officials
- Provided analytical support for DOE’s renewable energy R&D funding decisions

Union of Concerned Scientists Clean Energy Intern May 2005-October 2005

- Worked with the legislative and field staff to promote the inclusion of pro-renewable energy measures in the Energy Policy Act of 2005

State Public Interest Research Groups Policy Analyst August 2004-May 2005

- Analyzed and advocated for clean energy policies at the state and federal level

Publications available at <https://gridstrategiesllc.com/reports/>

MG-2: Georgia Power's response to data
request STF-PIA-2-3 - Attachment A

Exhibit has been redacted in its entirety.

MG-3: Georgia Power's response to data request STF-PIA-2-2 - Attachment.

Exhibit has been redacted in its entirety.

MG-4: Georgia Power's response to data
request STF-PIA-2-6 - Attachment

Exhibit has been redacted in its entirety.

MG-5: Georgia Power's response to data
request STF-PIA-2-3 - Attachment C

Exhibit has been redacted in its entirety.

MG-6: Georgia Power's response to data
request STF-PIA-1-13

Georgia Power Company
Docket No. 56765
Fuel Cost Recovery (FCR-27) Application
STF-PIA Data Request Set No. 1

STF-PIA-1-13

Question:

Please explain why Bowen is primarily fueled from Appalachian and Illinois Basin coal mines instead of lower-cost Powder River Basin coal mines.

Response:

The coal units at Plant Bowen became operational from 1971 to 1975 and were designed for Bituminous coals primarily sourced from Appalachian and Illinois Basin (“IB”) coal mines. The use of Powder River Basin (PRB) coal was very limited in the 1970’s and didn’t really become widespread in the Southeast until the 80’s and 90’s with the western railroad expansion and 1990 Clean Air Act Amendments. The Company explored switching Plant Bowen over the years and the various studies have shown that converting the coal units at Plant Bowen to be able to burn PRB coals would require a large amount of capital investment. In addition, even though the PRB coal is cheaper than Appalachian and IB coal on average per ton basis, there is a capacity reduction associated with PRB in comparison due to lower coal quality of subbituminous coal. Given the significant capital investment required and the lower expected capacity output with PRB coal, the switching of Plant Bowen to PRB coal would be uneconomic for customers.

MG-7: Georgia Power's response to data
request STF-PIA-1-3

Georgia Power Company
Docket No. 56765
Fuel Cost Recovery (FCR-27) Application
STF-PIA Data Request Set No. 1

STF-PIA-1-3

Question:

Please explain how the Company calculates the fuel cost used in determining the marginal cost of generation (item 2c above). Please explain whether this calculation is based on the contractual cost of fuel supply and transportation, the spot market price of fuel at that time, or other factors. If the coal supply or transportation contracts include any provisions for liquidated damages or other penalties for failing to meet minimum delivery quantities, take-or-pay provisions, or similar mechanisms, please explain if and how those provisions are accounted for in the fuel cost used in determining the marginal cost of generation from each coal unit.

Response:

Please see MFRP-13.5 submitted in the Company's initial filing submitted February 17, 2026 for an overview of how marginal cost of fuel was determined for the projected test period.

The marginal replacement costs for each gas-fired unit are typically updated once each gas trading day. These costs include the best estimate of the next day's gas prices based on Intercontinental Exchange ("ICE") average index pricing for the generating unit's supply plus any pipeline fuel, transportation, and fuel use tax adders.

The marginal replacement costs for each oil-fired unit are typically updated once each gas trading day. These costs include the best estimate of the next day's fuel oil prices based on the Oil Price Information Services ("OPIS") 10 AM rack average index pricing for the generating unit's supply terminal plus a transportation adder to have oil delivered to the unit based on the current fuel oil supply agreement.

Transportation for uncommitted coal is reflected in marginal replacement cost using the applicable active contract rate or recent carrier quote for the relevant origin/destination and time period. If the applicable transportation contract contains minimum-volume / take-or-pay provisions with liquidated damages (or similar shortfall charges), the marginal replacement cost of transportation component reflects those provisions only to the extent they affect the incremental cost of additional deliveries based on the timing of need:

- i. When forecast deliveries are below the contractual minimum, the component of transportation costs covered by the shortfall/liquidated damages is treated as fixed and excluded from the marginal replacement cost for incremental deliveries up to the minimum; and

Georgia Power Company
Docket No. 56765
Fuel Cost Recovery (FCR-27) Application
STF-PIA Data Request Set No. 1

- ii. Once forecast deliveries are at or above the contractual minimum, marginal replacement cost reflects the full applicable transportation rate for additional deliveries.

BEFORE
THE GEORGIA PUBLIC SERVICE COMMISSION OF
DOCKET NO. 56765

In re:

Georgia Power Company's Fuel Cost
Recovery (FCR-27)

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the Direct Testimony of Michael Goggin (Public Disclosure) on behalf of Sierra Club, NRDC, and SACE has been furnished by electronic mail on this 9th day of April, to the following:

Sallie Tanner

Executive Secretary
Georgia Public Service Comm.
244 Washington Street, SW
Atlanta, GA 30334
stanner@psc.state.ga.us

Jeffry C. Pollock

J. Pollock Incorporated
14323 South Outer 40 Road,
Suite 206 N
Town and Country, Missouri 63017-5734
jcp@pollockinc.com

Jeremiah Haswell

Kyle Leach

Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374
jhaswell@southernco.com
kleach@southernco.com

Robert Trokey

Justin Pawluk

Chris Collado

Tom Newsome

Jamie Barber

Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334
rtrokey@psc.ga.gov
jpawluk@psc.ga.gov
ccollado@psc.ga.gov
tnewsome@psc.ga.gov
jamieb@psc.ga.gov

Jennifer Whitfield

Amitav Kamani

Bob Sherrier

Alyssa Krantz

Southern Environmental Law Center
Ten 10th Street, NW, Suite 1050
Atlanta, GA 30309
jwhitfield@selc.org
akamani@selc.org
bsherrier@selc.org
akrantz@selc.org

Brandon F. Marzo

Steven Hewitson

Allison W. Pryor

Troutman Pepper Hamilton Sanders LLP

600 Peachtree Street NE, Suite 3000

Atlanta, GA 30308-2216

brandon.marzo@troutmansanders.com

steven.hewitson@troutman.com

allison.pryor@troutman.com

Charles B. Jones, III

Jim Kelleher

Georgia Association of Manufacturers 75

Fifth Street, NW

Suite 3412

Atlanta, GA 30308

cjones@gamfg.org

jkelleher@gamfg.org

Robert B. Baker

Robert B. Baker, PC

2480 Briarcliff Road, NE, Suite 6

Atlanta, Georgia 30329-3008

bobby@robertbbaker.com

/s/ Caden Koontz

Caden Koontz

Sierra Club

50 F St. NW, Eighth Floor

Washington, DC 20001

(202) 650-6075

caden.koontz@sierraclub.org

STATE OF GEORGIA
BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	)	
	)	
Georgia Power Company's	)	Docket No. 56765
Fuel Cost Recovery (FCR-27)	)	
	)	
_____	)	

DIRECT TESTIMONY
OF
JEREMY KALIN

ON BEHALF OF
NATURAL RESOURCES DEFENSE COUNCIL ("NRDC"),
SIERRA CLUB AND SOUTHERN ALLIANCE FOR CLEAN ENERGY ("SACE")

09 APRIL 2026

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LIST OF EXHIBITS

JK-Exhibit 1: Curriculum Vitae of Jeremy Kalin

JK-Exhibit 2: Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility
Regulators

Q: PLEASE STATE YOUR NAME, POSITION, AND ADDRESS.

A: My name is Jeremy Kalin. My business address is c/o Avisen Legal, P.A., 901 Marquette Avenue South, Suite 1675, Minneapolis MN 55402.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A: I was asked by the Natural Resources Defense Council (“NRDC”), Sierra Club and Southern Alliance for Clean Energy (“SACE”) to testify in this proceeding.

Q: PLEASE DISCUSS YOUR RELEVANT EXPERIENCE, PROFESSIONAL EXPERTISE, AND EDUCATIONAL BACKGROUND.

A: I am an advisor, attorney and shareholder at Avisen Legal, P.A. in Minneapolis, Minnesota. I am licensed to practice law in the State of Minnesota and the District of Columbia, first admitted to the Minnesota Bar in 2010. I serve as legal counsel to energy developers, investors, advocates, project hosts and state and local governments across the United States in my areas of expertise. I also serve as consultant and advisor in a number of capacities and organizations on energy project finance, energy policy and related business issues. I have attached a copy of my CV to my testimony (JK-Exhibit 1). I am also an author of the 2023 paper published by Rocky Mountain Institute (“RMI”), “Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility Regulators” which I have provided as an Exhibit to this testimony (JK-Exhibit 2).

I was elected to the Minnesota House of Representatives for two terms, where I served on the Energy Policy and Finance Committee, authoring numerous energy bills that became law including the Demand Efficiency Act, the Next Generation Energy Act, the Public Building Enhanced Energy Efficiency Program and the Commercial Property Assessed Clean Energy Act. I also authored the 2010 Ratepayer Protection Act calling for Commission action to better align utility financial incentives with macroeconomic factors and public policy goals at the state and federal level. From 2010 to 2017, I served as CEO of Eutectics Consulting LLC, a mission-driven

company focused on financing energy projects in underserved and untapped markets. While in public office, I served as state legislative liaison for the White House energy policy team, and later advised the U.S. Department of Energy Jobs Strategy Council under Democratic and Republican Secretaries of Energy. Among other projects, in 2013, I led the modernization of Minnesota's nationally-recognized Energy Assurance Plan, and have continued to be deeply engaged in emergency preparedness and response since then.

My undergraduate degree is from the University of Minnesota, I pursued graduate studies in the University of New Mexico School of Architecture and Planning for two years, and have a Juris Doctorate from William Mitchell College of Law in St. Paul, Minnesota.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A: Yes. I previously testified before the Georgia Public Service Commission in Docket 44902, in re: Georgia Power Company's 2023 Fuel Cost Recovery (FCR-26) Application.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: In my testimony, I provide the following:

1. A history of fuel-cost-passthrough policies, including Georgia's Fuel Cost Recovery mechanism;
2. An explanation of the "moral hazard" presented by Georgia's Fuel Cost Recovery mechanism, and why the Georgia Power request and the FCR itself continue to pose a threat to Georgia ratepayers' economic wellbeing and electricity reliability;
3. Other states' actions to reduce the moral hazard of fuel pass through policies, protect ratepayers and strengthen reliability;
4. Factors the Commission should consider in evaluating whether Georgia Power's significant rate increases are prudent and justifiable, in light of:
 - a. The Commission's invalidation of only 0.05% of all fuel expenses dating from FCR-21 to today;

- b. Georgia Power's implied admission that the utility has not taken any meaningful steps to reduce ratepayers' exposure to Georgia Power's fuel costs;
- 5. The reliability vulnerabilities to which Georgia Power's overreliance on natural gas as an electric generation source and the FCR-27 request exposes Georgia's entire electric sector;
- 6. Context for evaluating Georgia Power's proposed 200% increase in natural gas hedging authority to \$3.32 billion;
- 7. A brief discussion of Georgia Power's proposal to essentially eliminate the need for future Fuel Cost Recovery dockets by increasing the Interim Fuel Rider cap to 40%.
- 8. A recommendation to the Commission to:
 - a. Amend the FCR procedures under which the Commission evaluates the prudence, economic value and reliability impacts of FCR applications;
 - b. Amend the FCR testing period procedures to establish more reliable and accurate forecasts and benchmarks for FCR tariffs;
 - c. Reject most of the FCR-27 application and require that Georgia Power submit a revised FCR-27 application with:
 - i. updated natural gas price forecasts in light of the global natural gas volatility caused by the war in Iran and the Straits of Hormuz transit access challenges;
 - ii. greater clarity on the impact of increased oil prices and oil price volatility on the delivered coal forecast and the coal transportation services agreements entered into the Company since FCR-26;
 - iii. a natural gas hedging plan restricted to the current authority provided in FCR-26;
 - iv. an IFR threshold increase to \$300 million, but only if tied to a symmetrical fuel-risk-sharing and fuel-cost-sharing mechanisms

wherein Georgia Power is responsible for ten percent (10%) of the total cost of all fuel expense risk.

- d. Adopt the proposed FCR-27 tariff rate as an Interim Fuel Rider tariff, in order to provide timely relief to ratepayers until Georgia Power submits a revised FCR application and the Commission approves such revised application.
- e. Regardless of action on Georgia Power's FCR-27 application, the Commission should initiate a full Fuel Cost Recovery modernization docket, including requiring the utility to be responsible for some portion of fuel purchase risks and fuel purchase costs for all future FCR tariffs.

Q: WHAT DOCUMENTS DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A: I have reviewed Georgia Power's Direct Testimony; other Georgia Power filings as part of the docket; many of the Minimum Filing Requirement documents, and Georgia's Fuel Cost Recovery statute, Official Code of Georgia Annotated ("O.C.G.A.") § 46-2-26.

I have briefly reviewed other relevant sections of O.C.G.A. § 46-2-20 through 46-2-33, as well as Department 515 Rules of Georgia, Public Service Commission ("PSC"). I have also briefly reviewed previous Fuel Cost Recovery dockets and other Commission materials to which I refer in this testimony. All of the material I reviewed is public data; I did not receive any trade secret or otherwise confidential information.

I. HISTORY OF FUEL COST PASSTHROUGH MECHANISMS

Q: HOW DOES GEORGIA'S FUEL COST RECOVERY MECHANISM COMPARE WITH THE OTHER STATES, INCLUDING THE HISTORY OF FUEL PASS THROUGH CLAUSES?

A: During most of the first 100 years of the electric power industry, fuel costs were the complete responsibility of utilities. The National Electric Light Association ("NELA") argued in 1907 for what we know today as the electric utility regulatory compact, recognizing that financially

sustainable electric utility business models depended on access to capital to expand utility service; accepting state regulation and public oversight of capital investments would provide these utilities stable access to capital. NELA's Subcommittee on Public Regulation and Control wrote, "[I]t should be impressed upon the officials controlling public-utility corporations that the public will is that these companies shall exist, not primarily to make dividends upon certain investments of capital, but as the most efficient means of supplying the public's needs."¹

In the interest of consumer protection and incentivizing efficient production of electricity, the newly created public utility commissions included fuel costs as just one of the utility's many costs of doing business. These "inputs" were not a unique cost category requiring special ratemaking treatment.

When World War I disrupted oil, coal and gas supply, fuel prices increased significantly with significant month-to-month volatility. In one of many war-time measures, electric utilities asked regulators for insulation against these fuel-price swings and the resulting major financial risk. Commissions and other regulators responded by authorizing temporary fuel-pass-through policies, which were terminated soon after the end of World War I.

World War II sparked a similar global disruption of energy supply, amidst extensive economy-wide rationing. Regulations again adopted 100% fuel pass-through-policies, provided utilities relief from unprecedented price volatility and supply challenges. Amidst victory gardens and ration books, utility customers likely understood that the higher cost of electricity – including the complete passthrough to ratepayers of electric generation fuel costs – as their war effort contributions. The end of the war brought with it the end of the fuel pass through regimes, and for nearly three more decades, electric utilities bore full responsibility for all of their fuel costs.²

¹ Vol. 1, National Electric Light Association, *Thirtieth Convention, Papers, Reports, and Discussions*, p. 642 (1907), available at <https://play.google.com/books/reader?id=hXtNAAAAAYAAJ&pg=GBS.RA2-PA28&hl=en>.

² Electric Consumers Resource Council, *Fuel Adjustment Clauses & Other Cost Trackers* (Sept. 5, 2023), available at <https://perma.cc/PP42-GDKT>.

The 1970s rise of Organization of the Petroleum Exporting Countries (“OPEC”) and the associated oil scarcity led to renewed demands from utilities the full fuel-pass-through tariff of the wartime eras. State legislators and utility commissions adopted fuel pass through policies, ultimately enacting statutes such as Georgia’s Fuel Cost Recovery Statute, O.C.G.A. § 46-2-26, adopted by the Georgia Legislature in 1979.

Unlike the world wars, the OPEC crisis did not end with any formal treaty or declaration. Neither the Georgia Legislature nor the PSC have revisited this 100% fuel-pass-through policy; many states have similarly let this temporary policy persist without sufficient scrutiny.

Q: DO ALL STATES REQUIRE THAT UTILITIES PASS THROUGH 100% OF FUEL COSTS AND FUEL RISKS TO RATEPAYERS?

A: No. Some states have enacted statutes that specifically require 100% pass-through of fuel costs and fuel risks to ratepayers. Many states, like Georgia, have fuel cost recovery statutes that provide the Commission with flexibility as to the amount of utility fuel costs to be passed to ratepayers. Some states do not have any specific fuel cost pass through statutes but rely on Commission orders.

Q: DOES GEORGIA’S FUEL COST RECOVERY STATUTE, O.C.G.A. § 46-2-26, REQUIRE 100% OF FUEL COSTS TO BE PASSED THROUGH TO RATEPAYERS?

A: No.

Q: CAN YOU EXPLAIN?

A: While I am a lawyer, I am not licensed to practice law in Georgia. My observations are based on several years of work inventorying and reviewing state fuel pass through policies.

In O.C.G.A. § 46-2-26(c), the statute requires the utility to propose “base rate tariffs to recover those [fuel] costs.” The statute does not require the utility to propose a rate tariff to recover all of its fuel costs, and the statute does not require the Commission to adopt a rate tariff authorizing a utility to recover all of its fuel costs. Further, I have not found any Commission rule or other administrative guidance that requires the Commission must approve a utility’s fuel rate tariff such

that the utility recovers 100% of its fuel costs; Georgia’s fuel cost recovery regime appears only to require that the Commission may approve a fuel cost recovery tariff. O.C.G.A. § 46-2-26(e) requires the Commission to “issue an order stating the base rates to be used by the utility” going forward, providing the Commission with significant flexibility on the amount of the base rates to be charged and collected from ratepayers.

Consistent with other sections of the Georgia Code and under Commission rules and policies, the Commission can modify the proposed fuel tariff from the utility’s application. The Commission has done exactly that in other FCR dockets. In 2005 the Commission reduced Georgia Power’s FCR tariff proposed by Georgia Power,³ and in 2000 the Commission made multiple changes to the proposed FCR tariff alongside consideration of other pending rate-related matters by the utility.⁴ The Commission has also rejected the proposed FCR tariff in favor of alternative FCR tariffs, including in dockets 19142-U and 21229-U in 2005, when the Commission required extended amortization periods.

Q: GIVEN THIS HISTORY, HOW DOES GEORGIA POWER’S PROPOSED FCR-27 TARIFF FIT IN WITH RECENT FCR RATES FOR THE COMPANY?

A: This following table accounts for all June through December Secondary Distribution customer FCR tariff rates from FCR-24 through the proposed FCR-27:

FCR-24	3.1718 cents per kWh
FCR-25	3.5484 cents per kWh
FCR-26	4.5876 cents per kWh
FCR-27	3.7214 cents per kWh

³ *Order* (May 19, 2005), Ga. Pub. Serv. Comm’n, Dkt. No. 19142, *available at* <https://psc.ga.gov/search/facts-document/?documentId=82630>.

⁴ *Final Order* (Mar. 30, 2000), Ga Pub. Serv. Comm’n, Dkt. No. 11884, *available at* <https://psc.ga.gov/search/facts-document/?documentId=37553>.

Georgia Power's proposed FCR-27 tariff represents a per kWh increase of 17.33% from FCR-24, adopted in 2015, recognizing that the utility's FCR-27 proposal fails to address the looming risks that could very well cause the FCR-27 fuel cost forecast to fall significantly short of actual costs, for reasons I will discuss shortly.

Q: CAN THE COMMISSION BE CERTAIN THAT THE PROPOSED FCR-27 TARIFF WILL NOT TRIGGER FURTHER FCR INCREASES?

A: No, I do not believe so, for reasons I will discuss further, as well as those disclosed by Messrs. Houston and Berrigan in their Direct Testimony. First, Georgia Power's under-recovery of fuel expenses is projected to grow \$88 million just in the five-month period of December 2025 through May 31, 2026.⁵ The company also admits to increasing fuel expense in the FCR-27 forecasted period, which I believe is likely understated significantly.⁶ The Energy Information Administration's ("EIA's") natural gas price update for January 2026, released in March 2026 after the Houston and Berrigan testimony was filed but before the commencement of the war in Iran, shows a 69% increase in natural gas prices to electric generation consumers from January 2025, from \$6.21 to \$10.20, and a 107% increase from January 2024, from \$5.08 to \$10.20. In their testimony, Messrs. Houston and Berrigan recognize the significant uncertainty inherent in their FCR-27 proposal, when they state "Taken together, these factors suggest a tighter supply-demand balance and the potential for continued natural gas price volatility."⁷

Second, the company relies on a large-load revenue forecast that must be realized in order to achieve the presumed downward pressure on rates in the company's next base rate case. Messrs. Houston and Berrigan claim that these large load customers "will bear the appropriate cost responsibility in each hour for the fuel cost" and that these large load customers will "reduce rate

⁵ *Direct Testimony of Adam D. Houston and Matthew S. Berrigan on Behalf of Georgia Power Company in Support of Georgia Power's Fuel Cost Recovery (FCR-27)*, 4 (Feb. 17, 2026), Ga. Pub. Serv. Comm'n, Dkt. No. 225466, available at <https://psc.ga.gov/search/facts-document/?documentId=225466> [hereinafter "Testimony"].

⁶ *Id.* at 5.

⁷ *Id.* at 15.

pressures for all Georgia Power customers.”⁸ The company properly recognizes in this FCR-27 application that the Fuel Cost Rate tariff reviews must be considered in the context of rate case dockets.⁹ Georgia Power is not alone in forecasting the significant growth of data centers, but like any large project – whether a new load or a new generation facility – interconnection capacity, financing, local permitting and any number of other issues are likely to mitigate or slow the pace of such growth. The Company’s FCR-27 application appears to require that a significant amount of new data centers be built in order to achieve the claimed benefits or general ratepayer protections.

Third, the company’s Projected Fuel Costs, as summarized in Table 3 of the Houston Berrigan testimony, relies heavily on increased coal generation across the company’s fleet.¹⁰ The Company claims a 33% reduction in the marginal coal cost assumptions for the FCR-27 test period compared with the FCR-26 historical period, stating such reductions are due in part to “significant lower transportation prices” achieved via newly-negotiated service agreements entered into by the company since FCR-26.¹¹ The Company’s claim requires serious scrutiny, since transportation costs generally account for 41% of all coal purchases for electric power plants,¹² and all or nearly all of the coal delivered to generating plants in Georgia are transported from out of the state.¹³ Coal is typically transported by diesel-powered trains, and the Strait of Hormuz closures and access challenges have spurred an immediate four-fold increase in crude oil tanker shipping rates in the Middle East; a backup of vessels confined in the Persian Gulf with already-loaded crude oil has reduced the availability of global tanker capacity and increased tanker rates.¹⁴ This sustained global supply of crude oil has quickly increased domestic rates of petroleum products, including diesel.

⁸ *Id.* at 18.

⁹ *Id.* at 17.

¹⁰ Testimony at 16.

¹¹ *Id.* at 18.

¹² EIA, *Coal Explained*, available at <https://www.eia.gov/energyexplained/coal/prices-and-outlook.php> (last updated Apr. 17, 2024).

¹³ EIA, *Georgia, Analysis*, available at <https://www.eia.gov/states/GA/analysis> (last updated Mar. 20, 2025).

¹⁴ EIA, *Middle East Crude Oil Tanker Rates Reached a Multi-Decade High in March* (Mar. 26, 2026), available at <https://www.eia.gov/todayinenergy/detail.php?id=67386>.

Fourth, it is hard to overstate the impact of the war in Iran on fuel cost volatility and the potential impact on Georgia ratepayers. The 2022 Russian invasion of Ukraine was a major cause of the \$2.2 billion under-recovery that led to the FCR-26 rate increase. In evaluating the impact of the first 14 trading days after the onset of the Iran hostilities, the Purdue University Center for Agriculture found that the Brent Crude Oil spot price increase in March 2026 is significantly greater than the same period following the first hostilities in Ukraine; the total Brent Crude Oil spot price is higher in real dollars already than the same point in 2022.¹⁵

The war in Iran also bears significant price volatility risks for natural gas markets. While the Henry Hub spot price for natural gas has remained fairly stable for the first weeks of hostilities along the Persian Gulf, the global natural gas supply has tightened. As the price of natural gas exports from the United State rises, domestic suppliers will continually face temptation to shift from local demand to the more lucrative export market, particularly in the Southeast United States with access to methane export infrastructure.¹⁶

Q: HOW SIGNIFICANT IS THE FUEL COST RECOVERY TARIFF IN TERMS OF OVERALL ECONOMIC COST?

A: The company incurred \$8.409 billion in fuel costs during the three years of the FCR-26 historical period,¹⁷ an average of \$2.803 billion per year.

¹⁵ Ken Foster & Bernhard Dalheimer, *The Iran Conflict, Energy Prices, and U.S. Farm Profitability: A Balanced Assessment*, Purdue University Center for Commercial Agriculture (Mar. 31, 2026), available at <https://ag.purdue.edu/commercialag/home/paer-article/the-iran-conflict-energy-prices-and-u-s-farm-profitability-a-balanced-assessment>.

¹⁶ Jamison Cocklin, *Europe's Storage Deficit Expected to Continue Pulling U.S. LNG During Strong Restocking Season*, Natural Gas Intelligence (Feb. 19, 2026), available at <https://naturalgasintel.com/news/europes-storage-deficit-expected-to-continue-pulling-us-lng-during-strong-restocking-season/>.

¹⁷ Testimony at 9 (citing a 2.2% increase of \$185 million above budgeted costs, reflecting a total cost of \$8.409 billion).

The company's projected fuel cost for the FCR-27 two-year test period is \$7.073 billion,¹⁸ an average of \$3.536 billion per year. If realized, Georgia Power will incur a 26% increase in fuel costs from FCR-27.

The Company states that large load customers will pay for their required fuel costs, as noted. However, the Company has not clearly stated the extent to which additional fuel costs will be incurred regardless of whether large loads are realized (in other words, whether large data centers are actually built and begin operating), or if some fuel costs will be incurred by the company and cannot be curtailed or avoided should the large load growth not be realized, or fall short of the forecasted load growth. As discussed later, the Company's FCR-27 proposal would position the Company to have committed significant sunk costs into serving these large loads, including but not limited to the hedging premiums incurred months or years in advance of new loads coming online. All of the Company's ratepayers will face these increased hedging premiums if any project large load is not realized within the FCR-27 period, or at all.

Q: WHAT DO YOU ESTIMATE IS THE TOTAL FUEL SPEND BY GEORGIA POWER FROM THE FCR-21 APPLICATION DATE THROUGH THE FCR-26 HISTORICAL PERIOD?

A: Because I have not accessed any trade secret data, I have relied on the Company's statements in their public filings in FCR proceedings, Annual Reports and annual 10-K disclosure filings to the Securities and Exchange Commission. In doing so, I conservatively estimate, that Georgia Power has incurred between \$29 billion and \$40 billion dollars on fuel purchases for the generation of electric power, from 2010 through May 31, 2026.

Q: IN REVIEWING GEORGIA POWER'S FUEL COST RECOVERY RATE REQUEST, WHAT STANDARD SHOULD THE COMMISSION APPLY?

¹⁸ *Id.* at 16.

A: The Fuel Cost Recovery statute states that the Commission shall “make appropriate adjustment for any reported fuel cost that is the result of illegal or **clearly imprudent conduct** on the part of the utility.”¹⁹

Q: HOW OFTEN HAS THE COMMISSION DETERMINED THAT ANY OF GEORGIA POWER’S PROPOSED FUEL COSTS WERE IMPRUDENT?

A: From FCR-21 through this current docket, the Commission has not ever disallowed any Georgia Power proposed fuel costs for fuel cost recovery from ratepayers for imprudent conduct, nor for illegal conduct.

Q: HAS GEORGIA POWER EVER BEEN REQUIRED BY THE COMMISSION TO REDUCE THE FUEL COSTS RECOVERED FROM RATEPAYERS THROUGH THE FCR TARIFF?

A: From FCR-21 through this current docket, no. Since 2010, the only circumstances under which the company has reduced its total fuel costs recovered from ratepayers has been through voluntary stipulation.

Q: WHAT IS THE TOTAL AMOUNT THAT THE COMPANY HAS AGREED TO REMOVE FROM FUEL COST RECOVERY TARIFFS?

A: Since 2010, from FCR-21 through this current docket, the company has voluntarily agreed to remove from the fuel cost balance a total of just \$14.5 million.²⁰ Working from the most conservative estimate of \$29 billion dollars spent by Georgia Power on fuel costs during the same period, this accounts for just 0.05% of all fuel costs incurred by Georgia Power. A more precise calculation of all FCR-claimed fuel cost balance expenses over the period will likely result in an even smaller percentage of voluntarily removed costs. In other words, the Commission has permitted the Company to collect from ratepayers at least 99.95% of all claimed fuel costs.

¹⁹ Ga. Code Ann. § 46-2-26(h) (2024) (emphasis added).

²⁰ \$6 million in the FCR-24 stipulation agreement; \$1.5 million in the FCR-25 stipulation agreement, and \$7 million in the FCR-26 stipulation agreement.

Q: AS AN EXPERIENCED BUSINESS LAWYER AND ADVISOR, HOW WOULD YOU CHARACTERIZE THIS SMALL AMOUNT OF VOLUNTARY REMOVAL BY THE COMPANY?

A: I think a reasonable reading is that the company views this periodic, de minimis voluntary removal of 0.05% of all fuel costs as just a cost of running the business. Any similar enterprise would almost certainly internalize these small recovery reductions in their general business projections.

II. THE “MORAL HAZARD” INHERENT IN THE FUEL COST RECOVERY TARIFF

Q: WHAT IS A “MORAL HAZARD?”

A: A moral hazard occurs when one party is incentivized to take more risk than they normally would because that party is insulated against such risk.²¹ If the decisionmaker is so insulated from the consequences of a decision, such decisionmaker is likely to take a bigger risk. The extent of the moral hazard – and such insulation – determines the scope of risk the decisionmaker is willing to take on.

Q: HOW IS THE MORAL HAZARD EMBODIED IN GEORGIA’S FUEL COST RECOVERY STATUTE, O.C.G.A. § 46-2-26?

A: While O.G.C.A. 46-2-26 does not require the utility to collect all of its fuel costs from ratepayers, the statute permits the utility to set fuel recovery rates that pass along 100% of the fuel costs to ratepayers.²² As discussed previously, the 1970’s energy crisis spurred action to address global fuel volatility, not just in electric utility fuel procurement but across all fuel-consuming industries. Every state traded complete utility insulation from fuel cost volatility – at the cost of consumer exposure to such wild price swings.

²¹ See generally Mark Thoma, *Explainer: What Is Moral Hazard*, CBS News (Nov. 22, 2013), available at <https://www.cbsnews.com/news/explainer-moral-hazard/>.

²² Georgia PSC, *Fuel Cost Recovery*, p. 2, available at http://www.psc.state.ga.us/electric/regulation/Fuel_Cost_Recovery.pdf (last visited Apr. 6, 2026).

Q: IS THE COMMISSION REQUIRED TO IMPLEMENT FUEL COST RECOVERY IN A MANNER THAT CONTINUES AND EXACERBATES THE MORAL HAZARD?

A: I think the statute does provide plenty of flexibility to better allocate risk between the utility and the ratepayers, particularly through fuel-cost-risk-sharing.

III. FUEL RISK SHARING IN OTHER STATES

Q: WHAT IS FUEL-RISK-SHARING?

A: Under a fuel-risk-sharing policy, the utility sets a total fuel budget at the beginning of the rate-setting period based on expected fuel costs. At the end of each portion of the rate-setting period – typically on an annual basis – if actual costs increase from the approved benchmark, the utility pays a percentage of the difference, passing along such savings to ratepayers by otherwise reducing fuel costs that such customers would have paid. If actual costs decrease, the utility retains a portion of those cost savings as an incentive, with the balance of savings passed along to ratepayers.

Note that the terms “fuel-risk-sharing” and “fuel-cost-sharing” are sometimes used interchangeably, or are shortened to “fuel sharing.”

Q: IS TARIFF SETTING IN FUEL-RISK-SHARING MUCH DIFFERENT IN 100% FUEL PASS THROUGH POLICIES, SUCH AS GEORGIA’S FCR?

A: While the fuel cost forecasting and other elements of Georgia’s current fuel cost recovery tariff continue to face accuracy challenges, many of the components of fuel-risk-sharing policies are in place in Georgia. I will discuss the key questions to consider when reviewing fuel-risk-sharing proposals, but the basic foundations of the policy architecture are already in place.

Q: WHAT IS THE STATUS OF FUEL-RISK-SHARING TODAY IN OTHER STATES?

A: As of the date of this testimony, at least 9 states require some form of fuel-risk-sharing by their investor-owned-utilities: Hawaii; Idaho; Missouri; Montana; Oregon; Vermont; Washington;

Wisconsin, and Wyoming.²³ In the last three years, at least three states have advanced fuel-risk-sharing policies: Colorado, Nevada and Virginia very recently.

Q: IN THE LAST FORTY YEARS, HAS ANY STATE REQUIRED 100% UTILITY RESPONSIBILITY FOR FUEL COSTS?

No state has determined it necessary to completely eliminate the utility's ability to pass through the vast majority of fuel expenses to ratepayers without any utility exposure. In other words, no state has returned to 100% utility responsibility for fuel costs and fuel risks.

In the 8 states with existing fuel-risk-sharing policies, the current levels of fuel-risk-sharing range from 20% utility responsibility to single-digit utility responsibility. Some states that require smaller amounts of utility fuel-risk responsibility provide additional, overlapping incentives for utilities to further reduce their exposure to fuel price volatility.

Q: HAVE ANY STATE COMMISSIONS RECENTLY REVIEWED FUEL-RISK-SHARING POLICIES AT ANY DEPTH?

A: Each of the 9 states with fuel-sharing requirements have rejected attempts to eliminate the utility's responsibility for a portion of fuel risk. Wyoming recently reviewed extensive testimony and data in evaluating the effectiveness of their Energy Cost Adjustment Mechanism and the related Net Power Cost policy. In January 2024, the Wyoming PSC affirmed their current 20% utility fuel-sharing policy applied to Rocky Mountain Power to be in the public interest.²⁴ The Wyoming Commission came within one vote of increasing utility responsibility to 30%, as originally required in the 2003 initial fuel-sharing order.²⁵

Even in the rare cases where a state no longer requires fuel-sharing, these Commissions are again discussing fuel-sharing regimes. As recently as March 2025, in their March 2025 order

²³ Xavier Zheng et al., *How Fuel Cost-Sharing Can Deliver Savings for Utility Customers*, RMI (Feb. 26, 2026), available at <https://rmi.org/how-fuel-cost-sharing-can-deliver-savings-for-utility-customers/>.

²⁴ *Memorandum Opinion, Findings, and Order*, 50 (Jan. 2, 2024), Wyo. Pub. Serv. Comm'n, Dkt. No. 20000-633-ER-23, Rec. No. 17252.

²⁵ *Id.*

addressing Arizona Public Service’s fuel cost recovery tariff request, the Arizona Corporation Commission made it a specific point to explain the history of Arizona’s prior 90/10 fuel sharing and its removal as part of a settlement agreement, explaining: “The [2011] Decision did not find that the 90/10 provision was ineffective, just that Staff believed its elimination would benefit customers when fuel prices were lower, as they apparently were at that time (as evidenced by the lower base fuel rate). (See Ex. RUCO-13 at 25.)”²⁶ The Arizona Commission demurred on the question of reinstating this 90/10 fuel-sharing provision, calling it a “more difficult issue, in light of conflicting evidence.”²⁷

Q: IS THERE AN OPTIMAL AMOUNT OF UTILITY FUEL-RISK AND FUEL-COST RESPONSIBILITY IN ANY SUCH SHARING POLICY?

A: I do not believe it is worthwhile to even consider returning to the pre-OPEC days of assigning to the utility 100% of fuel cost and fuel risk responsibility. Fuel risk sharing requirements in those states with sharing suggest that allocating a small percentage of fuel risk and fuel costs to the utility can have a dramatic benefit for reliability, resource diversity, ratepayer protection and utility performance.

Q: DOES THE UTILITY HAVE ANYTHING TO GAIN BY ACCEPTING FUEL RISK-SHARING AND FUEL COST-SHARING?

A: Absolutely. When designed well, fuel-sharing policies provide utilities with more upside opportunity than downside risk.

I believe that the most effective fuel-risk-sharing policies are “symmetrical” and are not punitive. If the utility can actively reduce fuel risks and fuel costs, as determined in a Fuel Cost Recovery docket, the utility should be rewarded for such efforts. The total fuel risk and fuel cost savings to the ratepayer should exceed any additional earnings awarded to the investor-owned-

²⁶ *Decision No. 79293*, 193, FN 376 (Mar. 5, 2024), Ariz. Pub. Serv. Comm’n, Dkt. No. E-01345A-22-0144, available at <https://docket.images.azcc.gov/0000210704.pdf?i=1775600725806>.

²⁷ *Id.*

utility, of course. But designed well, a modernized Fuel Cost Recovery mechanism in Georgia will provide consistent benefits to the utility and to ratepayers.

IV. FACTORS THE COMMISSION SHOULD CONSIDER IN EVALUATING THE FCR-27 PROPOSAL

Q: IS IT APPROPRIATE TO VIEW FUEL COST RECOVERY DOCKETS IN ISOLATION?

A: No, I do not think so. And apparently neither does Georgia Power.

Fuel Cost Recovery dockets implicated Integrated Resource Plans, rate cases and specific plant Certificate of Need applications. I believe the Commission would be wise to consider the multiple factors and broader economic forces through a specific Fuel Cost Recovery modernization docket.

In their testimony, Messrs. Houston and Berrigan indicate that any evaluation of the economic impact of the FCR-27 tariff must be considered within the context of their next base rate case.²⁸ Messrs. Houston and Berrigan also explicitly reference the company's Storm Damage Recovery Application filing.²⁹ The Commission has frequently referenced rate cases and other dockets during considerations of FCR tariffs.

The inverse is also true. For instance, much of the FCR-26 rate hike and the FCR-27 vulnerabilities were discussed when the Commission took up the company's integrated resource plan ("IRP") and demand-side management ("DSM") Stipulation of 2022. Intervenors SACE and Southface Energy Institute specifically recommended that Georgia Power not proceed with planned expansion of natural gas generation and procurement, and that the Commission consider an order "setting an upper limit on the recovery of fuel costs for [the] PPAs to adequately protect ratepayers

²⁸ Testimony at 17.

²⁹ *Id.* at 4.

from market volatility and unprecedented price spikes.”³⁰ In his Direct Testimony in the 2022 IRP and DSM dockets, witness Ron Binz, former Chair of the Colorado Public Utility Commission, repeatedly highlight the risks associated with natural gas spikes.³¹

With the company’s total fuel costs rising now reaching \$3.3 billion a year as forecasted in FCR-27,³² and with natural gas and oil price volatility remaining high, the Commission would be wise to revisit whether to integrate Fuel Cost Recovery tariffs with general rate cases or specific Integrated Resource Plan dockets.

Q: YOU HAVE USED THE TERM “VOLATILITY” A FEW TIMES. WHAT IS VOLATILITY IN THE CONTEXT OF A FUEL COST RECOVERY TARIFF?

A: For commodities like gas or coal, “volatility” describes how quickly the price of a commodity changes over time. In economic and financial terms, volatility refers to the standard deviation of changes in a price variable over time. “Price volatility” does not necessarily mean that prices are increasing, or that prices are decreasing. Instead, price volatility means that prices are changing rapidly over a short period of time.

Q: NATURAL GAS PRICE VOLATILITY IS OFTEN DESCRIBED AS OUT OF THE UTILITY’S CONTROL AND “UNPRECEDENTED.” DO YOU AGREE?

A: No. Georgia Power has repeatedly been warned of the volatility and risk of relying on fuel-based power generation, as recently as the 2023 IRP Update and 2025 IRP.³³ As intervenors SACE and Southface stated, by only focusing on natural gas and coal as supply options, Georgia Power

³⁰ *SACE and Southface Energy Institute Post-Hearing Brief*, 18 (July 7, 2022), Ga. Pub. Serv. Comm’n, Dkt. Nos. 44160 & 44161, available at <https://psc.ga.gov/search/facts-document/?documentId=190679> [hereinafter “SACE/Southface Post-Hearing Brief”].

³¹ *Id.*

³² Testimony at 15.

³³ *Direct Testimony of Lucy Metz on Behalf of the Sierra Club and the Southern Alliance for Clean Energy*, 35 (Nov. 12, 2025), Ga. Pub. Serv. Comm’n, Dkt. Nos. 56298 & 56310, available at <https://psc.ga.gov/search/facts-document/?documentId=224479>.

left the Commission, and thus, the utility’s ratepayers, “a choice between two volatile, risky fossil fuels at the expense of innovative, cost controlled, and less risky renewables projects.”³⁴

The relationship between fuel price volatility, resource planning and rate cases are interconnected to the extent that the Commission should not consider fuel cost recovery without also addressing resource planning and overall rate setting; and the Commission should not consider rate setting and resource planning without simultaneously considering the impact of fuel cost recovery rates.

V. FUEL COST RECOVERY IMPLICATIONS FOR RELIABILITY

Q: DOES GEORGIA’S 100% PASSTHROUGH FUEL COST RECOVERY MECHANISM HAVE RELIABILITY AND HOMELAND SECURITY IMPLICATIONS?

A: Yes.

As required by the federal Department of Homeland Security’s Federal Emergency Management Agency (“FEMA”), the Georgia Emergency Management and Homeland Security Agency (“GEMA/HS”) maintains Georgia’s Emergency Operations Plan (“GEOP”). The GEOP is developed by GEMA/HS in coordination with other state agencies, non-governmental organizations and private sector partners and is aligned with the National Incident Management System, National Response Framework and the National Disaster Recovery Framework. Every four years, GEMA/HS updates the GEOP itself and all of the GEOP annexes, including Annex 12 – the Energy Annex.

Like all statewide Emergency Operations Plans, the GEOP takes the approach of “All Hazard Planning” including identification of past and potential future emergencies in the state. The GEOP then conducts a vulnerability analysis, a function of the built environment, local economy, demographics and environmental uses of a region. The GEOP states very clearly that damage

³⁴ SACE/Southface Post-Hearing Brief at 17.

and/or destruction to any of Georgia’s six critical lifeline sectors, including Energy, “represents enormous economic, social, and general functional costs to a community, while also impeding emergency response and recovery activities.”³⁵

The GEOP does not mince words in describing the public health, safety and lifeline support implications of events that would damage or destroy parts of the state’s Energy infrastructure, particularly for electrical power.³⁶

The 2024 GEOP identified several specific “Hazards of Concern” based on past emergencies as well as current and future vulnerabilities. During the period included by GEMA/HS for the GEOP, Severe Weather was the most common cause of declared disaster events in Georgia, accounting for 20 of 45 disasters.³⁷ Of these severe weather events through 2019, 4 were severe winter weather events – a Hazard of Concern identified three years before winter storm Elliott wreaked havoc in Georgia, and two years before Superstorm Uri created substantial natural gas price increases and subsequent price volatility for months, including substantial impacts in Georgia.

Emergency Support Function 12 – Energy Annex (“ESF-12”) supports the GEOP and provides guidance to prepare for, respond to, recover from and mitigate the effects of a disaster or emergency on Georgia’s Energy System, and is the principal conduit by which the critical energy infrastructure is protected and restored. The Commission assumes primary oversight of emergency and disaster operations pertaining to electrical infrastructure, including planning and coordinating preparedness and mitigation activities pertaining to electrical and natural gas infrastructures.³⁸

Specifically, ESF-12 requires that the PSC ensures “equitable provision and restoration of services to the public” during response and recovery phases of a disaster or emergency.³⁹ Good

³⁵ GEMA/HS, *Georgia Emergency Operations Plan*, p. 6 (Oct. 28, 2024), available at <https://gema.georgia.gov/what-we-do/planning> [hereinafter “GEOP”].

³⁶ *Id.*

³⁷ *Id.* at 7.

³⁸ GEMA/HS, *Emergency Support Function 12 (Energy) Annex to Georgia Emergency Operations Plan*, p. 4 (July 6, 2023), available at <https://gema.georgia.gov/what-we-do/planning>.

³⁹ *Id.* at 3.

emergency preparedness relies on redundancy of resources and supply options that can meet the emergent needs in case of a primary failure or disruption. In the simple statement of the EIS Council, a nonprofit organization focused on global disaster preparedness, “Redundancy is essential for ensuring the continuous operation of critical infrastructure.”⁴⁰

The Fuel Cost Recovery mechanism and policy of 100% pass through to ratepayers has incented Georgia Power to rely far too heavily on a single power generation source, leaving a significant portion of the state’s electricity supply vulnerable to a disruption from a number of hazards, such as severe weather or domestic terrorism.

Q: HOW MUCH DOES HAS GEORGIA’S RELIABILITY ON NATURAL GAS INCREASED OVER THE LAST FEW DECADES?

A: Since 1997, Georgia’s natural gas delivery to electric consumers has increased from 17,034 MMcf to 401,348 MMcf.⁴¹

Q: WHAT PERCENTAGE OF TOTAL CAPACITY DOES NATURAL GAS SUPPLY FOR THE COMPANY?

A: In the 2025 IRP, Georgia Power reported that natural gas consists of 44% of their 2025 summary capacity mix, and that coal consists of another 16%.

Q: CAN YOU RESTATE THE CONNECTION BETWEEN 100% FUEL PASS THROUGH POLICIES AND OVERRELIANCE ON FOSSIL FUEL?

A: Because utilities do not bear any financial cost or risk responsibilities for fuel, any increased in the cost or the volatility of purchased fuel is not born by the utility. The Fuel Cost Recovery mechanism provides a utility with a blank check of sorts to increase the throughput of fuel-based generation, even if non-fuel alternatives would provide greater value to ratepayers and greater resource diversity. Once a plant has been granted a certificate of public necessity the

⁴⁰ EIS Council, *The Role of Redundancy in Critical Infrastructure Protection*, available at <https://eiscouncil.org/redundancy-critical-infrastructure/> (last visited Apr. 8, 2026).

⁴¹ See EIA, *Natural Gas*, available at <https://www.eia.gov/dnav/ng/hist/n3045ga2a.htm> (data through Mar. 31, 2026).

equivalent, and absent any disallowance of costs for imprudence or illegally activity, the utility can be assured that all or nearly all of its fossil fuel expenses will be collected from ratepayers, even where the total operating costs of those power plants are now outside of the original economic cost-effectiveness calculation.

Q: DOES GEORGIA’S CURRENT FUEL COST RECOVERY MECHANISM ALSO HAVE LARGER NATIONAL SECURITY IMPLICATIONS?

A: Yes. Repeatedly, a significant number of retired three- and four-star Admirals and Generals have examined critical national security, energy and climate change issues as members of the Military Advisory Board convened by strategic think tank Center for Naval Analysis (“CNA”).⁴² These national security leaders declared as the first finding in their report “Ensuring America’s Freedom of Movement: A National Security Imperative to Reduce U.S. Oil Dependence:”

America’s dependence on oil constitutes a significant national security threat.
Our overreliance on oil is a national vulnerability.

While focused on oil’s impact on the transportation sector of the U.S. economy, these Admirals’ and Generals’ collective caution should also be applied to Georgia’s heavy reliance on natural gas as well. In the same report, these Admirals and Generals followed with a second key finding, which has become too real in light of the Iran war:

We chose our reduction target [of a 30 percent reduction in petroleum use] based on a specific military challenge. CNA analysis shows that if America used 30 percent less oil, our economy would have enough resilience to sustain the effects of a complete shutdown of the Strait of Hormuz (the narrow passage for international shipping between the Sultanate of Oman and Iran), or any other major shipping choke point, with little effect. That image is a satisfying one (particularly to those of us who have spent much of our careers focused on Persian Gulf threats), and offers as good a definition as any of oil independence and increased security.⁴³

⁴² CNA Military Advisory Board, *Ensuring America’s Freedom of Movement: A National Security Imperative to Reduce U.S. Oil Dependence*, CNA (Oct. 2011), available at <https://www.cna.org/analyses/2011/ensuring-americas-freedom-of-movement>.

⁴³ *Id.*

Q: IN LIGHT OF GLOBAL SUPPLY VULNERABILITIES, DOES GEORGIA POWER'S FCR-27 PROPOSAL HELP PROTECT AGAINST THE SUCH IDENTIFIED AND LONG-STANDING THREATS?

A: No. While each federal administration might emphasize one set of national security priorities over another, the general threat analysis and domestic preparedness requirements change very little. The utility's proposed expanded reliance on natural gas and coal generation and on diesel-powered coal transportation resources will exacerbate Georgia's vulnerabilities to global disruptions and to domestic hazards.

Q: WHY SHOULD THE COMMISSION CONSIDER OVERRELIANCE ON FUEL-BASED RESOURCES IN THIS FCR-27 APPLICATION AND NOT IN A RATE CASE OR AN INTEGRATED RESOURCE PLAN?

A: The IRP is, by rule, a "planning process" and does not provide a venue for evaluating the real-time, operational decisions that determine whether ratepayers are exposed to excessive costs.⁴⁴ The Company's own summary of the 2025 IRP includes cautionary notes that highlight the "risks and uncertainties" including "projected economic growth and load growth" and that "actual results [could] differ materially from management expectations [including] variations in demand for electricity, available sources and costs of natural gas and other fuels and commodities, the ability to control costs.... [and] impacts from geopolitical conflicts...."⁴⁵ The Company cannot dismiss this disclosure of risks as required boilerplate language under securities laws, as such disclosures must address all material risks to their operations and any potential return on investment. The roadmap provided by the 2025 IRP requires that the Commission ensure that the resource plan is implemented with proper care and diligence, including this FCR docket.

⁴⁴ Ga. Comp. R. & Regs. 515-3-4-.02(25) (Mar. 24, 2026).

⁴⁵ Georgia Power, *2025 Integrated Resource Plan, Georgia Power's Plan to Reliably, Economically Meet the Energy Needs of a Growing Georgia*, available at <https://www.georgiapower.com/content/dam/georgia-power/pdfs/about/2025-irp-one-page-summary.pdf>.

VI. HEDGING

Q: CAN YOU SUMMARIZE THE COMPANY'S PROPOSAL TO INCREASE THEIR USE OF NATURAL GAS HEDGING IN FCR-27?

A: Georgia Power has asked the Commission for authority to increase their use of natural gas hedging to 267% of FCR-26 levels.⁴⁶

Q: THE COMPANY STATES THEY ARE JUST INCREASING HEDGING FROM 40% TO 60%. WHY WOULD THAT SO DRAMATICALLY INCREASE THEIR HEDGING AUTHORITY?

A: The Company is currently allowed to hedge 40% of its budgeted natural gas burn up to 36 months. Table 3 of Messrs. Houston and Berrigan testimony states that the two-year FCR-26 test period total natural gas budget amounted to \$2.132 billion, for a total \$1.066 billion each year.⁴⁷ Over three years this amounts to \$3.198 billion. Forty percent (40%) of this total equals \$1.279 billion in hedging authority.

The Company is requesting authority to hedge up to 60% of its budgeted natural gas burn for up to 48 months. Table 3 of Messrs. Houston and Berrigan testimony forecasts a two year FCR-test period total natural gas budget of \$2.848 billion, for a total of \$1.424 billion each year. Over four years this amounts to \$5.696 billion. Sixty percent (60%) of this total equals \$3.147 billion in requested hedging authority.

\$3.147 billion authority is 267.2% greater than \$1.279 billion authority.

Q: WHAT IS THE EASIEST WAY TO UNDERSTAND HEDGING IN THIS CONTEXT?

A: Fuel supply hedging general takes two forms: Physical hedging and financial hedging.

Physical hedging involves the advance purchase, delivery and storage of the commodity, relying on the purchaser's calculated gamble that the price is lower at the date of purchase than it

⁴⁶ Testimony at 21.

⁴⁷ *Id.* at 16.

will be when the purchaser needs to use the commodity – or in the case of an electric utility, to burn the commodity to generate electricity.

Financial hedging involves a similar calculation, but binds the selling party (or commonly the brokering party) to deliver the commodity in the future for a price agreed upon at the time of the hedging contract. Instead of paying for the storage of the commodity in the case of physical hedging, the purchaser pays for the future delivery obligation of the seller (or the broker).

Q: HOW SHOULD THE COMMISSION EVALUATE GEORGIA POWER’S DRAMATIC EXPANSION IN HEDGING AUTHORITY?

A: The Missouri PSC conducted two workshops to assess the cost-effectiveness of investor-owned electric utility and local natural gas distribution company use of financial natural gas hedging.⁴⁸ The Missouri Commission staff report provides an effective summary of the considerations the Georgia Commission could use to evaluate Georgia Power’s 267.2% increase in natural gas hedging.

The Missouri report advises, “Hedging should be viewed as the cost of mitigating risk, and the gas market is not without risk.”⁴⁹

The Missouri report further advises, “Appropriate use of hedging instruments can take advantage of the [then-]current relatively low price of natural gas.” Noting that as of the date of this testimony, the Iranian hostilities have already increased the price of natural gas and the overall volatility of natural gas prices going forward, the Georgia Commission should recognize that the FCR-27 proposal is not being made during a time of low natural gas prices.

Energy sector advisory and consulting firm ICF International more deeply investigated the use of hedging, via long term contracts, in a paper published in 2011, authored by Vice President

⁴⁸ *Staff Report*, 1 (Apr. 8, 2013), Mo. Pub. Serv. Comm’n, File No. EW-2013-0101, *available at* <https://www.efis.psc.mo.gov/Document/Display/73082>.

⁴⁹ *Id.* at 6.

Bruce Henning.⁵⁰ Mr. Henning found that such long-term contracts can be a tool to manage and mitigate adverse impacts from short-term price movements “as part of a diversified portfolio.”

Mr. Henning warned that after-the-fact review of hedging effectiveness can be extremely difficult:

For regulated entities, the standard of review is whether the utility acted prudently given the information available at the time of the decision. As such, a comparison between the contract price and the *ex post* market prices is generally thought to be an inappropriate factual basis for a disallowance. Nevertheless, in most proceedings, exhibits are presented that make just such comparisons.

Instead, Mr. Henning states that regulators must take seriously their obligations in advance of hedging activity, particularly in a pre-approval authorization docket such as FCR-27:

Pre-approval can create risks for regulators (and the customers they represent) because they are in the position of approving management decisions without having access to all the information available to the utilities. It is this balancing of risks and opportunities that forms the basis for evaluating the benefits of a portfolio that includes an element of contracts (and other forms of hedges) that can provide increased price stability for gas market participants.

Mr. Henning’s concludes:

[T]here are issues and market disruptions that can occur in either extreme. A portfolio approach to contracting offers a possibility to mitigate the risks of either extreme... [T]here are legitimate reasons for the general move to short-term and indexed contracts. Even so, there are reasons to consider long-term contracts for a **minority portion** of a gas portfolio. (emphasis added)

Q: DOES GEORGIA POWER’S HEDGING EXPANSION REQUEST CONSTITUTE A “MINORITY PORTION” OF ITS NATURAL GAS PORTFOLIO?

A: No. Georgia Power’s requested 267.2% expansions of natural gas hedging authority would allow the utility to take significant risks relating to 60% of its total natural gas purchases. This is hardly a “minority portion” of a mixed portfolio of risk mitigation tools.

⁵⁰ Long-term Contracting for Natural Gas: Examination of the Issues that Affect the Potential for the Increased Use of Contracting to Stabilize Consumer Prices.

Q: DOES GEORGIA POWER’S HEDGING EXPANSION REQUEST CONSTITUTE A “MINORITY PORTION” OF ITS OVERALL GENERATION PORTFOLIO?

A: No. As explained previously, Georgia Power already relies too heavily on natural gas in terms of reliability and resource diversity. Further, Georgia Power is proposing to increase its reliance on coal generation during FCR-27, for which the company relies on hedging as well, including physical hedging.⁵¹

Q: GIVEN MR. HENNING’S CAUTION IN HIS PAPER, DOES THE COMMISSION HAVE ENOUGH INFORMATION TO TAKE THE RISKY STEP TO PROVIDE PRE-AUTHORIZATION FOR THE HEDGING EXPANSION AS REQUESTED?

A: No. For the reasons provided earlier, I do not believe approval of the hedging request is responsible.

VII. INCREASING THE INTERIM FUEL RIDER CAP

Q: WHAT IS THE HISTORY OF GEORGIA POWER’S INTERIM FUEL RIDER (“IFR”) CAP?

A: The Commission initially approved the Interim Fuel Rider IFR mechanism in FCR-21 in 2005. Over the years, Georgia Power’s IFR threshold has been increased as follows:

FCR-21	\$75 million
FCR-22	Unchanged from CFR-21 (Commission rejected staff recommendation of \$40 million)
FCR-23	\$200 million, up to 115% of FCR-23 rates

⁵¹ Ga. Pub. Serv. Comm’n, Dkt. No. 39638, Georgia Power Company Fuel Recovery No. 4, *available at* <https://psc.ga.gov/search/facts-docket/?docketId=39638>.

FCR-24 (IFR-2)	Unchanged from FCR-23
FCR-25	Unchanged from FCR-23
FCR-26	\$200 million, with authority to reach 140% of FCR-26 rates ⁵²
FCR-27	\$300 million

Q: THE COMPANY CLAIMS THAT THE IFR MECHANISM BENEFITS CUSTOMERS. DO YOU AGREE?

A: Like much of their FCR-27 application, Georgia Power improperly describes the IFR as a consumer protection mechanism. The IFR does not actually mitigate costs to ratepayers in any way. Instead, the IFR mechanism allows the utility to further shift risk to ratepayers, particularly during times of significant price volatility. As fuel costs increase and reach the IFR threshold, the Company merely passes along the utility's increased fuel costs to ratepayers. The utility is thus allowed to keep collecting more via the higher FCR tariff, effectively providing further disincentive to reduce fuel costs. The IFR accelerates the moral hazard of 100% fuel pass through costs.

Q: COULD THE COMMISSION RESPONSIBLY APPROVE EXPANDING THE IFR AUTHORITY?

A: If the Commission required Georgia Power to integrate expanded IFR authority with a fuel-risk-sharing mechanism, the moral hazard risk is likely to be greatly reduced, and ratepayers would likely benefit.

Q: ON WHAT GROUNDS OR PRECEDENT DO YOU BASE YOUR BELIEF THAT FUEL-RISK-SHARING WILL BENEFIT GEORGIA POWER AND RATEPAYERS?

⁵² The FCR-26 IFR approval was split between the under-collected revenue during FCR-25 and the forward-looking FCR-26. Only the FCR-26 change is reflected here.

A: In the nine states with fuel-risk-sharing today, their Commissions have found such policies to be in ratepayers' interest.

Further, RMI recently published a fuel-risk-sharing analysis in another southeastern state, North Carolina.⁵³ RMI modeled the likely impact on ratepayers and on utility shareholders over a five year period from 2020 through 2024. RMI found that fuel sharing could have saved ratepayers \$89 million during this high price volatility period, and shareholders would have earned an additional \$10.9 million. While North Carolina and Georgia are different states with distinct differences, the two states share some key factors: population; industry; electrical load and projected load growth; the majority of utility service provided by a multi-state investor-owned-utility, and a current policy of 100% fuel-pass-through rates. Where reasonable difference can be found between Georgia and North Carolina, the Commission would be wise to pursue a similar state-specific analysis from RMI to determine the scope of potential benefits if fuel-risk-sharing were in place in Georgia.

As described earlier, Commissions in Colorado and Nevada have actively engaged in developing fuel-risk-sharing policies after legislative action; in March 2026, the Virginia legislature has required that the Commission formally study fuel-risk-sharing as a tool to protect ratepayers.

Fortunately, Georgia's fuel-cost-recovery statute provides the Commission sufficient flexibility to approve fuel-risk-sharing within the overall fuel-cost-recovery tariff.

Q: WHAT SHOULD THE COMMISSION REQUIRE THE COMPANY TO INCLUDE IN A FUEL-RISK-SHARING PROPOSAL?

A: As laid out in JK-Exhibit 2 "Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility Regulators Fuel-Cost Pass-Through Reform," the Commission should ensure the Georgia Power proposal properly balances these factors:

⁵³ Zheng, *supra* note 22.

1. **The proper amount of fuel cost sharing and fuel risk sharing to be assigned to the utility.** There is not one “best” sharing amount that should be applied to all utilities because utilities vary in multiple ways. However, a utility responsibility of ten percent (10%) is often sufficient to incent utilities to more aggressively manage fuel risk exposure.
2. **Symmetrical or asymmetrical incentives and penalties.** A symmetrical fuel-cost sharing assigns the same percentage of fuel risk and fuel cost responsibility to the utility regardless of whether the actual fuel costs are higher or lower than expected. While both symmetrical and asymmetrical sharing policies can be structured to provide both rewards and penalties to the utility, I believe that a symmetrical sharing structure can be more easily understood by utility analysts, and still substantially benefit ratepayers.
3. **Straight sharing of fuel costs and risks, or the use of “deadbands.”** The simplest structure for a fuel-cost sharing mechanism is to always require the same level of utility fuel cost responsibility (e.g., 10 percent) regardless of how much the utility’s actual costs deviate from expectations or forecasts. Some sharing policies utilize a “deadband” approach that provides a preestablished margin of fuel cost changes in which a utility can pass through all of the fuel costs to ratepayers as they do today.
4. **Reliance on forecasts versus actual historic pricing.** Forecasting natural gas pricing can feel like an exercise in futility. Some states have adjusted the timing of fuel cost reviews to ensure greater reliability of actual pricing and costs, given the challenge of reliable forecasting.
5. **Retaining Hedging at Reasonable Levels.** As discussed above, while hedging permits the utility to purchase stability and price predictability in exchange for a premium payment for such future fuel supply, the company proposes to expand its use of hedging 267% to become its primary means of fuel cost management. Hedging can

be a useful tool, if primarily applied to a small portion of a utility's fuel purchases, and ratepayers are sufficiently protected from the impact of excessive hedging premiums.

Purchased Power. Georgia's Fuel Cost Recovery mechanism currently ensures that the fuel costs of purchased power are included in the utility's fuel rate calculations. Any risk-sharing and cost-sharing proposal should consider continuing this policy component, lest Georgia Power attempt to sidestep the fuel risk requirements strictly through Power Purchase Agreements rather than utility-owned assets.

VIII. SUMMARY

Q: CAN YOU SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS TO THE COMMISSION?

A: 1. I recommend that the Commission provide for more extensive reviews of Fuel Cost Recovery expenditures, tariff changes, forecasting, hedging authority and Interim Fuel Rider requests.

2. I recommend that the Commission more closely coordinate Fuel Cost Recovery dockets with rate cases and/or Integrated Resource Plan dockets to ensure consistent analysis and methodologies between all dockets, and to ensure that the interrelated issues are considered particularly with respect to reliability and ratepayer impact.

3. I recommend that the Commission reject Georgia Power's requests in the FCR-27 application, with the exception noted below with respect to the FCR-tariff rate as an Interim Fuel Rider tariff, and required that Georgia Power submit a revised FCR application with the following updates:

- i. Updated natural gas price forecasts in light of the global oil and natural gas volatility caused by the war in Iran;
- ii. Updated coal price forecasts in light of increased oil prices and the impact on the company's coal transportation services agreements;

- iii. A natural gas hedging plan restricted to the current authority provided in FCR-26.
- iv. An IFR threshold increase to \$300 million, but only in the condition that Georgia Power submit a proposal for fuel-risk-sharing and fuel-cost-sharing mechanisms wherein the company is responsible for ten percent (10%) of the total cost of all fuel expenses, with the opportunity to be rewarded for reducing overall fuel costs against an established benchmark so long as ratepayers realize at least ninety percent (90%) of the savings from such reduction.

4. I recommend that the Commission adopt the proposed FCR-27 tariff rate as an Interim Fuel Rider tariff, in order to provide timely relief to ratepayers until Georgia Power submits a revised FCR application and the Commission approves such revised application.

5. Regardless of action on Georgia Power's FCR-27 application, the Commission should initiate a full Fuel Cost Recovery modernization docket, including requiring the utility to be responsible for some portion of fuel purchase risks and fuel purchase costs for all future FCR tariffs.

Q: DOES THIS COMPLETE YOUR TESTIMONY?

A: Yes. Thank you.

JK-Exhibit 1:
Curriculum Vitae of
Jeremy Kalin

JEREMY KALIN

901 MARQUETTE AVE SO, SUITE 1675 MINNEAPOLIS, MN 55402 • 612.584.3400 • JKALIN@AVISENLEGAL.COM

EDUCATION

- J.D. **William Mitchell College of Law**, St. Paul, MN.
University of New Mexico, School of Architecture and Planning, Albuquerque, NM.
- B.F.A. **University of Minnesota**, Minneapolis, MN.

PROFESSIONAL EXPERIENCE

- Attorney and Shareholder, Avisen Legal P.A.** 2019 - present
- Impact Counsel practice focused on low-carbon project finance and early-stage investment. Practice areas include energy policy; climate finance and related impact investment; solar electricity and energy efficiency; greenhouse gas reduction and related projects.
 - Clean energy financing and impact investment consulting for underserved and untapped markets in clean energy, clean water and green infrastructure.
 - General Counsel for venture capital funds investing in technology companies.
 - Admissions: Minnesota and the District of Columbia.
- Kalin LLC, Principal** 2017 - 2023
- Clean energy financing and impact investment consulting for underserved and untapped markets in clean energy, clean water and green infrastructure.
 - Built and launched multiple award-winning low- and moderate-income solar finance platforms for U.S. Department of Energy.
 - Built and launched Credit Unions' CU Green® clean energy investment platform.
- Senior Advisor, National Caucus of Environmental Legislators (NCEL)** 2016 - 2022
- National, bipartisan non-profit organization supporting state lawmakers advancing clean energy and resilient communities policies across all 50 states.
- Senior Advisor, GOVERNING Institute** 2014 - 2020
- Advisor and Speaker on Infrastructure, Workforce and Clean Energy Economy
- Eutectics®, CEO** 2010 - 2018
- Nationally-recognized, mission-driven clean energy finance consulting firm with over \$273 Million in projects in progress or completed nationwide.
 - Clients include: U.S. Department of Energy; City of Morris (MN); Baltimore City (MD); Chisago County HRA-EDA; Philadelphia (PA) Energy Authority; St. Paul PHA; The Nature Conservancy; University of Minnesota; etc.
- State Representative, Minnesota House of Representatives District 17B (Chisago County)** 2007 - 2011
- **Coalition of Legislators for Energy Action Now (CLEAN), Chair;** Obama White House bipartisan task force of legislative leaders on clean energy and climate policy.
 - **Minnesota Green Jobs Task Force, Co-Chair.**
 - **Legislative Chief Author:** 2010 Property Assessed Clean Energy (PACE) Act; 2009 Green Jobs Act / ARRA Energy Appropriation; 2008 Military and Overseas Voter Act; 2007 Demand Efficiency Act (*selected legislation*).
- Vice-Chair, East Central (MN) Regional Development Commission** 2004 - 2006
- Vice-Chair and Chisago County Representative on regional economic development authority serving Pine, Isanti, Chisago, Kanabec and Mille Lacs Counties.

SELECTED COMMUNITY SERVICE

Mississippi Headwaters Fund Advisory Board , The Nature Conservancy	2016 – 2018
The Violence Project Research Center , Board Member	2020 - 2024
Safety and Security Committee Chair , Shir Tikvah Synagogue	2018 - present
Jewish Family and Children's Service of Minneapolis , Director	2013 - 2021
Capital Expansion Working Group, Innovative Housing Network , Chair	2016 - 2017
FBI Citizens Academy , Minneapolis Division	2018
Minnesota Chamber of Commerce , Energy Policy Committee	2014 - 2016
State Innovation Exchange (SiX) , Founding Advisory Board	2012 – present
Overseas Vote Foundation , Advisory Board	2009 - 2012
James J. Hill Business Reference Library , Board Member	2010 – 2012
Chisago County (MN) Land Use Coalition	2004 - 2006
East Central (MN) Arts Council	2004 – 2006

SELECTED AWARDS AND RECOGNITION

Royal Society of the Arts , Fellow	2018 - 2022
British American Project , Fellow	2014 - present
Progress Minnesota 2017 Honoree (Eutectics)	2017
Midwest Energy Efficiency Alliance , Inspiring Leadership Award	2008
Legislator of Distinction , League of Minnesota Cities	2008
Legislative All-Star , Fresh Energy Minnesota	2007
Graduate Teacher of the Year , University of New Mexico, School of Architecture and Planning	2003

TEACHING EXPERIENCE

University of Minnesota , College of Design, “Design Thinking for Public Policy”
University of New Mexico , Graduate Teaching Assistant, School of Architecture and Planning
Massachusetts College of Art , Visiting Faculty
University of Minnesota College of Liberal Arts , Art Department, Teaching Assistant

SELECTED RECENT SPEAKING APPEARANCES

IMPACT , United States Green Building Council, Minnesota
American Institute of Architects , National Conference
Minnesota Real Estate Journal , Energy Summit
National Press Club , GOVERNING Outlook
United States Senate , Climate and Energy Security briefing
Center for Climate Strategies Forum on State and Subnational Leadership , United Nations Conference of Partners (COP15), Copenhagen, Denmark
University of Minnesota , College of Design, Commencement Speaker
National Press Club , United States Green Building Council Green Schools Caucus national launch
The White House , State Leadership on Clean Energy

Energy Efficiency Finance Forum, American Council for an Energy Efficient Economy
Georgetown University Climate Center, State Leadership on Climate and Energy
Good Jobs, Green Jobs Conference, Blue-Green Alliance Conference
Midwest Energy Solutions Conference, Midwest Energy Efficiency Alliance

SELECTED RECENT ARTICLES

Learning to Share: A Primer on Fuel-Cost Pass-Through Reform, Pearl Street Station Finance Lab, April 2023

Commentary: Clean Energy Still Trumps Partisan Politics, Midwest Energy News, November 2016

Sustainable: The Business Case for Going Green, Finance & Commerce, June 2016

Minnesota Community's Energy Focus Gives It Edge in National Competition, Midwest Energy News, June 2016

Minnesota Firm Has a New Approach to Clean Energy Financing, Midwest Energy News, May 2016

Energy Finance Advisor Helps Businesses Go Green, Minneapolis Star Tribune, October 2014

PACE Creating Efficiency Opportunities, Midwest Energy News, June 2014

'SolarNote' Aims to Reduce Complexity in Financing, Finance & Commerce, February 2014

From Commodity to Service: Why the Capitalization Model for Electric Regulation is Failing Minnesota, J.D. thesis paper, June 2010

JK-Exhibit 2:
Strategies for
Encouraging Good
Fuel-Cost
Management: A
Handbook for Utility
Regulators (2023)



Strategies for Encouraging Good Fuel-Cost Management

A Handbook for Utility Regulators



Report / July 2023

Authors and Acknowledgments

Authors

Joe Daniel

Rachel Gold

Jeremy Kalin, Avisen Legal

Albert Lin, Pearl Street Station Finance Lab

Kaja Rebane

Authors listed alphabetically. All authors are from RMI unless otherwise noted.

Contacts

Joe Daniel, jdaniel@rmi.org

Rachel Gold, rgold@rmi.org

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Kaja Rebane, Jeremy Kalin, Albert Lin, Joe Daniel, and Rachel Gold, *Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility Regulators*, RMI, 2023, <https://rmi.org/insight/strategies-for-encouraging-good-fuel-cost-management/>.

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Acknowledgments

The authors thank the following individuals for graciously offering their insights to this work and serving as advisors on this project. Inclusion on this list does not indicate endorsement of the report's findings.

- Travis Kavulla, NRG
- Mark LeBel, RAP
- Ron Lehr, independent consultant
- Annie Levenson-Falk, Minnesota CUB
- Janine Migden-Ostrander, Pace Energy and Climate Center
- Sonny Popowsky, Retired Consumer Advocate of PA
- Ted Thomas, Energize Strategies
- Frederick Weston, RAP

Energy Foundation provided funding to RMI to support this work. The findings presented in this work were independently authored by RMI, and RMI is solely responsible for the views expressed.



About RMI

RMI is an independent nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut greenhouse gas emissions at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; and Beijing.

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Executive Summary

Ensuring that rates are affordable and fair to customers is central to the mission of the regulatory commissions that oversee public utilities in the United States. Regulators operationalize this charge in many ways, from conducting detailed analyses of utility investment plans to carefully tailoring programs to the needs of low-income customers. However, in many jurisdictions little attention is paid to controlling fuel costs, which are a major factor driving recent increases in electricity bills.

Fuel costs represent a sizable portion of electric utility customers' bills, and fuel-price volatility can drive further bill increases with little notice. For example, in the wake of winter storm Uri in 2021, natural gas shortages caused prices to spike. Months later, regulators across the country were asked to approve utilities' requests to recover billions of dollars from customers to cover unexpected fuel costs.¹ Russia's 2022 invasion of Ukraine also caused coal and gas prices to increase dramatically.

The sustained high natural gas prices of 2022 drove the single largest year-on-year increase in electric bills.² The high energy bills are undoubtedly connected to the \$16 billion in unpaid energy bills and massive increases in utility shutoffs in that time frame.³ Those utility disconnections can have severe impacts, including potential eviction, loss of child custody, and even death.⁴ Fortunately, utility regulators can do something to help avoid future harms to captive customers.

In most jurisdictions, fuel costs are handled through a regulatory mechanism known as a fuel adjustment clause (FAC).ⁱ Unlike most components of utility rates, a FAC enables the utility to recover exactly what it spent on fuel — so if the company manages to reduce its fuel costs, it retains none of the savings, and if it spends more than budgeted, its customers pick up the bill. This gives utilities that operate under FACs little incentive to manage their fuel costs carefully, and it gives regulators limited visibility into whether the utility spent more than was necessary.

However, FACs were not always the norm. Until the latter part of the 20th century, regulators typically handled fuel costs in the same fashion as most other components of utility rates. An estimate of expected fuel costs was built into the basic rates utilities charged for service (i.e., “base rates”), and the utility was expected to fund its fuel purchases with whatever amount it collected in this fashion. Unlike under a FAC, no ex-post true-up to the utility's actual expenditures was performed.

The status quo is already unaffordable for many people who struggle to pay their electric bills, and FAC policies that give utilities little incentive to manage fuel costs carefully are exacerbating this problem. Fortunately, FACs are ripe for revision due to technological advances and evolving markets. Vertically integrated electric utilities have more options than ever before to reduce their reliance on expensive and price-volatile fuels.ⁱⁱ These opportunities include switching to fuel-free generating resources, negotiating more favorable supply contracts, and taking steps to reduce the amount of fuel needed to meet customer

ⁱ In this handbook, the term FAC refers to all policies that enable utilities to collect what they actually spent on fuel from customers through an ex-post true-up. However, the names used to refer to these policies vary by state (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

ⁱⁱ Electric distribution companies in restructured states may also have opportunities to negotiate supply contracts and support demand-side management, but this handbook focuses on vertically integrated utilities.

needs (e.g., by working to conserve energy and shift demand). In contrast, customers have few strategies available to reduce fuel costs, so requiring them to continue bearing all fuel-price risk under FAC policies is increasingly unreasonable.

Fortunately, multiple regulatory strategies are available to reduce utility fuel costs. This handbook presents six reform options that regulators can use to encourage utilities to carefully manage their fuel costs and adopt cost-effective fuel-free resources. We also examine key questions related to each option and, where relevant, highlight examples of states that have already implemented these policies. The six reform options we discuss are:

- **Fuel-cost sharing.** This policy creates a financial incentive for the utility to carefully manage its fuel costs by requiring it to bear part of the risk of fuel-cost volatility. Under a typical fuel-cost sharing policy, the utility captures a share of the savings if it can reduce fuel costs below expected levels, and it also bears a share of any cost overruns. Fuel-cost sharing has already been implemented by a number of states, though the design details of these policies vary. For states adopting this option, we recommend the use of historical values or externally derived forward price indexes from public sources to avoid potential gaming risks. Regulators could elect to apply fuel-cost sharing to proposed new power plants, and they could have the utility lock in the price forecast used during plant approval as the amount utilities are allowed to recover from customers for fuel to run the plant over its lifetime.
- **Fuel-cost true-up removal.** This reform represents a return to the ratemaking approach that was standard before FACs became the norm. As under a FAC, an estimate of expected fuel costs is built into base rates — but unlike a FAC, no ex-post true-up is performed to match the funds recovered from customers to the utility's actual expenditures. Although no state has implemented this policy to replace a FAC, many precedents exist from the years before states adopted their FACs. This policy would shift the risk of fuel price volatility back onto utilities.
- **Fuel-risk reduction tariffs.** This strategy consists of implementing new retail tariffs that both create an incentive for the utility to reduce fuel costs and reduce participating customers' exposure to fuel-cost volatility. Such tariffs could be structured in various ways, such as by fixing the per-kilowatt-hour (kWh) rate used to recover fuel costs (and not truing it up afterward) or by offering customers a subscription-style tariff with a flat monthly charge. A number of states have implemented tariffs with this basic structure, though their motivation for doing so has not focused specifically on fuel costs.
- **Planning and procurement.** Many opportunities exist to reform resource planning and procurement in ways that encourage better fuel-cost management. These include updates to long-term planning processes, closer scrutiny of fuel-price projections, locking in forecasts for new generation, requiring all-source solicitation and procurement, the use of fuel management plans, and refinements to how utilities utilize hedging. Some states have implemented one or more of these policies to update planning and procurement.
- **Strategies to increase access to information.** It can be difficult for regulators to determine whether the fuel costs a utility presents for recovery through a FAC are unnecessarily high, so strategies that increase regulators' and stakeholders' access to information can encourage utilities to contain their fuel costs. These include making fuel-supply contract terms more transparent, utilizing enhanced prudence reviews, requiring regular audits, and facilitating broader and deeper stakeholder engagement in regulatory processes.

- **Efficiency ratio.** This is an emerging concept that regulators can consider, though it does not currently have a track record comparable to the other policy options. An efficiency ratio consists of a financial incentive tied to a production-cost-efficiency metric. In other words, it is a type of performance incentive mechanism (PIM) that encourages the utility to reduce the average cost of producing a megawatt-hour (MWh) of power.

These six policy options offer regulators a variety of possible strategies to reform existing FAC policies. Both utilities and the jurisdictions they operate in vary, so there is not likely to be a single “best” policy for every circumstance. The key questions we discuss in relation to each policy highlight some of the important design choices regulatory commissions are likely to face, and regulators may identify additional opportunities to tailor policies to local needs as reform discussions proceed. We encourage commissions to also consider the benefits of adopting more than one reform. For example, particularly strong synergies are likely to exist between strategies that increase access to information and the other policy options we discuss.

Given the impact that fuel has on both customer bills and the carbon emissions of electric utilities, we urge commissions to consider changing the way that utilities recover fuel costs from customers. Recent years have brought a raft of affordability challenges to states around the country, and we expect these trends to continue due to uncertain and volatile gas prices, the need to upgrade the grid to ensure resilience and replace aging distribution infrastructure, and required capacity expansions to accommodate the move toward electrification.



Because FAC policies give electric utilities little incentive to carefully manage their fuel costs, regulatory commissions should investigate and take action to reform these policies. This handbook is intended as a resource to support these important regulatory discussions.

Introduction

Fuel costs represent a sizable share of the total cost of producing electricity from power plants. These costs can also fluctuate substantially from month to month as fuel prices and quantities change. The magnitude and volatility of fuel costs make it imperative that utilities manage them carefully, but under typical ratemaking practices they have no financial incentive to do so. This is because of the widespread use of a policy known as the fuel adjustment clause (FAC).ⁱⁱⁱ

FACs are rate riders that automatically true up the revenues collected from customers to match the utility's actual fuel expenditures.^{iv} Although a utility's fuel costs are generally subject to a prudence review by its regulatory commission before they can be recovered, in practice the effectiveness of these reviews tends to be limited due to the information asymmetry between the utility and the regulator and the structure of the dockets wherein the prudence review occurs. Regulators often find it difficult to determine whether the receipts submitted by the utility were in fact the best use of customers' money. This is because regulators may not have good visibility into the effort the utility put into negotiating lower fuel prices, what fuel-free alternatives were available to the utility, and other factors. This often results in near-automatic approvals of requests for cost recovery and, as a consequence, little incentive for the utility to carefully manage its fuel costs.

This is problematic because the utility is the party best positioned to manage fuel-cost risk. Although fuel prices are not entirely under the utility's control, the company generally can negotiate more favorable fuel-supply contracts and take steps to reduce the amount of fuel needed to meet demand (e.g., by working to conserve energy, shift demand, or procure nonfuel alternatives). In contrast, customers have little ability to manage fuel-cost risk — yet FACs unfairly shift this risk entirely onto their shoulders. Vertically integrated utilities, which generate their own power to supply customers, are particularly able to manage fuel-cost risk by shifting their generation portfolios to fuel-free alternatives.^v As a result, these utilities are the focus of this handbook, although some of the policy options we discuss may be relevant for other energy utilities as well.

FACs create a situation that economists refer to as “moral hazard,” which exists when one party makes the decisions while another bears the risk of those decisions. By insulating the utility from the risks of poor fuel-cost management decisions — and also not rewarding the utility for making good decisions — a FAC gives it little incentive to work hard to reduce fuel costs. By transforming fuel costs from a major business expense to a side consideration, FACs enable poor fuel-cost management decisions that undermine affordability and perpetuate utility reliance on carbon-intensive fuel-based generation resources.

iii In this handbook, the term FAC refers to all such policies, but in some states they have different names (e.g., the Energy Adjustment Clause in Iowa, Energy Cost Recovery in Alabama).

iv FACs are an example of what is known in regulatory parlance as a cost tracker. FACs are not the only type of cost tracker, but they (along with purchased-power cost trackers) are the most ubiquitous.

v Vertically integrated utilities are those that own generation, transmission, and distribution capacity, though most also purchase some power from other generators to meet customer demand. Electric distribution companies do not own generation yet they may also have opportunities to reduce fuel costs, such as by negotiating better supply contracts and supporting demand-side management. Though this handbook focuses on vertically integrated utilities, some of the policies discussed could be appropriate for electric distribution companies as well.

A FAC is typically implemented in several steps. First, the utility develops a forecast of future fuel costs, including estimates of both prices (e.g., \$/million British thermal units) and quantities (e.g., the share of total demand that will be met by gas- or coal-fired generation). This forecast is then built into the rates that the utility can charge its customers for electric service — specifically, as part of the volumetric component (i.e., the per-kWh rate customers pay). After the rates take effect, the revenues collected through this rate component are compared with the utility’s actual expenditures on fuel, and the cumulative difference is tracked over time via a balancing account.^{vi} Periodically, the utility applies for the balance to be trued up by adjusting the FAC rider; the regulator considers the utility’s application and approves the expenditures for recovery if they are deemed prudent (this usually happens in a dedicated fuel-cost recovery proceeding). Once the fuel costs are approved for recovery, the value of the FAC rider is adjusted to collect the additional revenue from customers (or to refund money if the utility collected more than it spent on fuel). The FAC rider typically appears as a separate line item on customer bills.

FACs are the norm today, but this was not always the case. Until the latter part of the 20th century, fuel costs were generally not given special treatment. Instead, they were handled in the same fashion as most other components of utility rates. Namely, the commission would approve a utility estimate of future fuel costs, which were then built into rates, and the utility could apply to raise its rates if the gap between the expected and actual fuel costs became too great. This approach established predictable per-kWh rates for customers and also rewarded the utility for limiting its actual fuel costs.

This changed in response to the fuel-price volatility caused by major geopolitical events during the previous century. In the wake of the two world wars, some utilities sought relief from exposure to fuel-price risk from their regulatory commissions and were granted temporary FACs. Then following the 1970s oil embargo, utilities across the country persuaded regulators to institute FACs with no sunset dates, and in some cases they even convinced legislators to write FAC policies into state statutes. As a result, FACs became the status quo nationwide.

However, the time has come to end the use of FACs for fuel-cost recovery. Due to an array of technological advances, utilities have more control than ever before over the amount they spend on fuel. Today, cost-effective solar and wind generation, battery storage, virtual power plants, and the managed charging of electric vehicles all provide new avenues to reduce reliance on fuels like natural gas and coal.

Retiring FAC policies could help motivate utilities to take full advantage of these new opportunities, which could reduce both customer costs and carbon emissions. This handbook presents six policy options that regulators can consider as alternatives to traditional FAC policies. We explore key questions regulators might consider in policy design, and, where relevant, we offer examples from US states with such policies.

vi In regulatory accounting terms, this variance is tracked over time through a regulatory asset (or regulatory liability).

Fuel-Cost Sharing

Fuel-cost sharing creates a financial incentive for the utility to carefully manage its fuel costs. Under a typical fuel-cost sharing mechanism, the utility can earn more if it reduces fuel costs and must bear a share of the burden if those costs rise. In other words, this reform exposes the utility to a portion of the fuel-cost volatility risk, so it is no longer fully insulated from fuel-cost changes as it is under a traditional FAC. Instead, under fuel-cost sharing the utility has some “skin in the game.”

In fuel-cost sharing, an estimate of expected fuel costs is first built into rates, and then just part of the difference between the revenues collected and the utility’s actual fuel expenditures is trued up. As is the case for a traditional FAC, this true-up is performed through a rider that applies an additional charge or credit to customer bills. The key difference between a traditional FAC and this policy option is that fuel-cost sharing trues up only part of the difference between the utility’s *expected* and *actual* fuel costs.^{vii}

Key Questions

Fuel-cost sharing can be implemented in a variety of ways. The most important questions that policymakers are likely to face include the following:^{viii}

How should the expected value be set? Because fuel-cost sharing functions by truing up only part of the difference between the expected and actual fuel costs, an “expected” level of fuel costs must be determined by the regulator. This expected value can be based on either *forecasted* or *historical* values. Although forecasts are the most common approach used today by states that have adopted fuel-cost sharing, they can open the door to gaming. Specifically, if a forecast is used to set the expected value of fuel costs, the utility can benefit financially either by reducing fuel costs relative to the forecast or by inflating the forecast.

To avoid creating an incentive to inflate the forecast, regulators can instead base the expected value on historical fuel expenditures (e.g., a five-year rolling average of past fuel costs). If a forecast is used, regulators should consider using forward price indexes (e.g., NYMEX futures for natural gas are publicly available) rather than relying on the utility’s bespoke modeling.^{ix} Additional design decisions around the expected value will also need to be made. These include whether the forecast (or historical values) should be based on just the individual utility or a relevant peer group, whether a third party should be responsible for any tasks (e.g., developing the forecast), and what (if any) historical period of fuel expenditures should be considered.

vii Performing a true-up that brings the revenues collected in line with the actual costs incurred is often referred to as passing through these actual costs to customers. For example, a traditional FAC passes through 100% of the utility’s actual fuel costs, whereas a fuel-cost sharing mechanism may pass through 90% of these costs. In this handbook, we do not use the term pass-through in this way, but readers may encounter it in other contexts.

viii For additional discussion of some of these questions, see Albert Lin, Jeremy Kalin, and Kaja Rebane, *Learning to Share: A Primer on Fuel-Cost Pass-Through Reform*, Pearl Street Station Finance Lab, 2023, <https://www.pssfinancelab.com/post/can-we-share-the-cost-of-fuel>.

ix Regulators should also ensure that any data source they use has sufficiently liquid trading to populate a credible sample, and that it includes buyers that are not rate-regulated utilities subject to this kind of cost-of-service regulation (e.g., industrial customers, merchant shippers). Where regulators face a choice between a less liquid trading point near the load the utility serves and a more liquid hub farther away, they may want to consider using the latter, subject to adding or subtracting a basis differential associated with observed pipeline rates or other clearly measurable factors.

How often should the expected value be updated? Although it may make sense to update the expected value at the time of a general rate case, a regulator could choose to reset it more frequently. For example, a special docket could be used to reset the expected fuel cost quarterly or annually, and that amount could then be recovered through a separate rider. However, updating the expected value too frequently could reduce the strength of the incentive created by the fuel-cost sharing mechanism. For instance, if the expected value is updated monthly, it may end up tracking actual fuel costs too closely, with the result that the mechanism functions similarly to a typical FAC.

How much sharing should occur? The amount of sharing should be high enough to motivate the utility to manage its fuel costs carefully, but low enough to avoid exposing the utility to unreasonable risk. Because utilities vary, there is not one universally “best” sharing amount. For example, sharing 5% of fuel costs (i.e., truing up 95% of the difference between expected and actual fuel costs) may be appropriate for a utility that is highly dependent on natural gas, whereas sharing 30% of fuel costs may be feasible for a utility with a less price-volatile resource mix (e.g., one that is high in coal or renewables).^x

Should deadbands or other thresholds be used? The simplest approach to fuel-cost sharing is to apply the same sharing percentage regardless of how close or far actual fuel costs end up being from the expected value. This approach, which is sometimes called straight sharing, is most common among existing fuel-cost sharing policies. However, another option is to change the amount of sharing when this difference crosses a specific threshold. For example, a mechanism could feature no sharing if actual fuel costs are within a certain percentage of expected fuel costs — a design called a deadband. Alternatively, a mechanism could feature several bands with different sharing percentages (e.g., 20% sharing if actual fuel costs are within 5% of the expected value, 10% sharing if actual fuel costs are between 5% and 10% of that value, and 5% sharing if the difference is greater than 10%).

Deadbands and other thresholds have both potential benefits and drawbacks, which regulators should consider carefully during the design process. One potential benefit of a deadband, specifically, is that it can simplify policy administration. Outcomes that fall within the deadband do not require any adjustment to the fuel-cost rider that appears on customer bills, which reduces the need for prudence reviews and associated litigation. One drawback is that deadbands and other thresholds can create an uneven incentive structure for the utility. For instance, if the utility’s share of fuel costs drops dramatically when a particular threshold is crossed (e.g., from 20% to 5%), the company may have little financial incentive to manage its fuel costs when it expects them to deviate from the expected value by more than that amount (such as during a period of high gas prices). Another drawback of complex banded structures is that they can be hard for customers to understand.

Should the mechanism be symmetrical or not? Another design question is whether the mechanism should operate differently depending on whether actual fuel costs end up being higher or lower than expected. Under a symmetrical mechanism, the financial rewards to the utility when fuel costs are lower than expected are a mirror image of the penalties to the utility when fuel costs are higher than expected. Under an asymmetrical mechanism, the rewards and penalties are structured differently. For example, a regulator could design an asymmetrical mechanism that trues up 95% of the deviation between expected and actual fuel costs when costs are lower than expected but just 85% when costs are higher than expected. In general, symmetrical mechanisms are viewed as more fair to the utility, create more consistent incentives for utility performance, and are easier for customers to understand than asymmetrical mechanisms. When the risk is asymmetrical, however, an asymmetrical sharing adjustment may be appropriate.

^x Percentages presented here are for illustration purposes only. Regulators should conduct quantitative analysis looking at their utility’s specific fuel mix to determine fuel-sharing percentages, as even two utilities in the same state might have different fuel mixes and therefore require different sharing percentages.

How should the true-up be conducted? The timing and duration of the true-up of expected to actual costs is another design consideration. As is the case with the true-up under a FAC, the true-up under fuel-cost sharing can be operationalized in different ways. For example, because positive and negative fluctuations in fuel costs tend to cancel each other out over time, performing true-ups every month or quarter will tend to result in more variable customer bills than performing them annually.^{xi} Regulators concerned about rate shock may wish to perform less frequent true-ups, or to spread the cost recovery (or refund) needed to implement the true-up over a longer time period.

Should purchased power costs be included? Most vertically integrated utilities purchase some power from other parties, and they typically recover 100% of these purchased-power costs from customers via a true-up that operates much like a traditional FAC. Because generated and purchased power are substitutes, applying a sharing mechanism to one and not to the other may encourage gaming. For instance, the utility may purchase more power when fuel prices rise even if this is more costly for customers. Incorporating purchased power in the fuel-cost sharing mechanism can avoid this type of perverse outcome.^{xii} Most fuel-cost sharing mechanisms today include purchased power or exist alongside mechanisms that track it.

Should sharing apply equally to all plants? Though fuel-cost sharing is typically implemented in the same fashion for all of a utility's fuel costs, this need not be the case. For example, a regulator that wants to focus the utility's attention on making better investment decisions going forward could apply a higher sharing percentage to new generating plants than to existing plants. If a commission were to apply fuel-cost sharing only to new plants, it could also lock in the fuel-price forecast used at the time of approval.

Should the amount of sharing increase over time? Once fuel-cost sharing is implemented, a utility can be expected to find ways to reduce its reliance on price-volatile fuels — and over time, the utility may be capable of managing a greater share of the remaining fuel-cost volatility risk. Recognizing this, a regulator may wish to ratchet up the sharing percentage over time to continue to create a strong incentive for the utility to improve further. Doing so on a forward-looking basis would give the utility better visibility into the timing and magnitude of future changes than would an ad-hoc approach.

Could fuel-cost sharing undermine electrification? The electrification of home heating, transportation, and other end uses will result in increased electric demand on the grid. Unless the new demand is met entirely by fuel-free generation, this will result in higher total fuel costs. Therefore, a fuel-cost sharing mechanism that penalizes the utility for higher-than-expected total fuel costs would tend to discourage it from supporting electrification. However, if used in concert with policies supportive of electrification, fuel-cost sharing instead could help create an incentive to meet the increased demand with new fuel-free resources (e.g., wind, solar) and to proactively manage new loads (e.g., electric vehicle charging) to shift usage away from high-cost hours.

Regulators could also address the potential impact of fuel-cost sharing on electrification more directly. One way could be to design the fuel-cost sharing mechanism with a carve-out for beneficial electrification. A second way could be to create a separate performance incentive mechanism (PIM) for beneficial

xi Performing true-ups annually also enables any normal seasonal variations in fuel costs to be netted out.

xii Exposing the utility to a share of fuel-cost risk could encourage it to shift its generation portfolio toward renewable resources, as these do not require fuel purchases. In this way, fuel-cost sharing could support state decarbonization goals. However, purchased power includes electricity generated from both fuel-fired and fuel-free resources, so purchased-power cost sharing would not be expected to drive decarbonization in the same way. Where reducing carbon emissions is an important policy goal, regulators could tailor the purchased-power sharing mechanism to support it. For example, the sharing mechanism could be designed in a way that distinguishes between different types of generation resources (e.g., it could apply a higher sharing percentage to fossil-fuel-fired resources than to renewables).

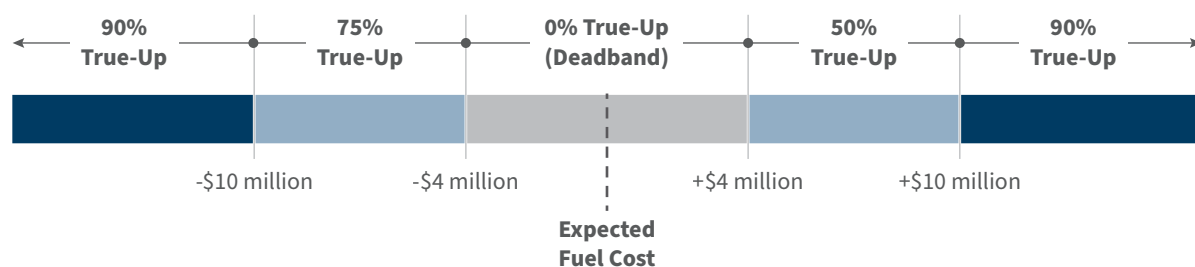
electrification that offsets the negative impact of the fuel-cost sharing mechanism.^{xiii} A third possibility could be to structure the fuel-cost sharing mechanism to operate on a per-MWh basis rather than a total-cost basis, though this has the downside of creating an incentive to sell more electricity (i.e., a throughput incentive) whenever fuel prices dip below expected levels. We refer to such a mechanism as a type of “efficiency ratio”; for further discussion, see [page 27](#).

State Examples

Wyoming is one state that has implemented fuel-cost sharing. Rocky Mountain Power’s Energy Cost Adjustment Mechanism (ECAM) trues up the utility’s actual net power costs (which include purchased power) to its forecasted costs in a symmetrical fashion.⁵ The ECAM utilizes a straight-sharing approach. The mechanism previously shared 30% of fuel costs (i.e., the mechanism trued up 70% of the difference between expected and actual costs), but regulators subsequently updated the policy to share just 20% today.^{xiv}

Washington has a fuel-cost sharing policy called the Power Cost Adjustment Mechanism (PCAM) for Pacific Power. The PCAM includes purchased power, relies on forecasts, and employs an asymmetrical banded design. The design features a deadband of \$4 million on either side of the forecast within which no true-up is made. If actual costs exceed this amount, there are two sharing bands: within the first (up to \$10 million), 50% of the difference is trued up; and within the second (over \$10 million), 90% is trued up. If actual costs are less than expected, there are also two sharing bands: within the first (down to -\$10 million), 75% of the difference is trued up; and within the second (less than -\$10 million), 90% is trued up. This banded structure is illustrated in [Exhibit 1](#). Under the current PCAM, the difference for a single year is recovered from customers over two years to reduce rate shock.⁶

Exhibit 1 Banded Design of Pacific Power’s Fuel-Cost Sharing Mechanism



RMI Graphic. Source: RMI

^{xiii} For example, if the utility’s average fuel cost per kWh is \$0.02 and the sharing percentage is 10%, the fuel-cost sharing mechanism would create a \$0.002 penalty for every kWh of new load. A PIM that rewards the utility \$0.002 per kWh of beneficial electrification would offset this penalty, and a PIM that offered more than this could create a financial incentive for the utility to pursue electrification.

^{xiv} These sharing percentages can be found on Rocky Mountain Power’s tariff sheets. For the present 80% true-up policy, see Rocky Mountain Power, *Schedule 95: Energy Cost Adjustment Mechanism*, Original Sheet No. 95-6, P.S.C. Wyoming No. 17, issued June 25, 2021. For the previous 70% true-up policy, see Rocky Mountain Power, *Schedule 95: Energy Cost Adjustment Mechanism*, First Revision of Amended Original Sheet No. 95-6, P.S.C. Wyoming No. 16, issued October 27, 2017. The utility’s current tariff can be downloaded at https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/rates/095_Energy_Cost_Adjustment_Mechanism.pdf.

Oregon employs fuel-cost sharing subject to an earnings test. For example, Portland General Electric has an Annual Power Cost Variance Mechanism, which shares 10% of the difference between expected and actual costs (i.e., 90% of the difference is trued up) outside of a deadband. However, this occurs only if sharing does not cause the utility's earnings to deviate by more than 100 basis points from its commission-approved return on equity. The deadband is asymmetrical (no sharing occurs if actual costs are between \$15 million less than forecast and \$30 million more than forecast) and the mechanism includes purchased power.⁷



Missouri also has fuel-cost sharing mechanisms in place for Ameren, Evergy, and Liberty utilities. These mechanisms are all symmetrical, feature a straight-sharing design with a 5% sharing percentage (i.e., 95% of the difference between expected and actual costs is trued up), rely on forecasts, and include purchased power.⁸ In a naming convention that may be confusing for those working in other states, these mechanisms are referred to as fuel adjustment clauses.^{xv}

Hawaii uses a fuel-cost sharing mechanism for the Hawaiian Electric Companies (HECO).⁹ The Energy Cost Recovery Clause (ECRC) takes a straight-sharing approach and employs forecasts to set the expected value that is built into rates. Under the mechanism, HECO trues up 98% of the difference between expected and actual fuel costs in a symmetrical fashion. The utility's annual financial exposure under the ECRC is capped at \$2.5 million.

xv This differs from how we use this term in this handbook, in which we define a FAC as a mechanism that trues up 100% of the difference between expected and actual fuel costs.

Fuel-Cost True-Up Removal

Rather than reducing the extent to which expected fuel costs are trued up to actual fuel expenditures (as in fuel-cost sharing), the true-up can be eliminated entirely. This would mean that fuel costs would not receive special ratemaking treatment — they would simply be recovered in the same fashion as most utility costs.

Expecting utilities to fund their fuel expenditures without a rider may seem like a radical idea today, but this was standard practice until the mid-20th century. Removing the true-up would shift fuel-price volatility risk back to the utility, which is in a much better position to manage that risk than its customers. In other words, this policy option would restore the balance between utilities and customers that traditional ratemaking achieved. It would also give the utility a very strong incentive to seek ways to reduce its reliance on price-volatile fuels.

However, suddenly removing the true-up could create financial difficulties for a utility that has structured its current business model on the assumption that customers will bear all fuel-cost volatility risk. For example, if natural gas prices increase sharply and the utility relies heavily on gas generation, the impact on the utilities' financials could be drastic. Regulators interested in this reform should therefore proceed carefully and consider appropriate steps to protect the utility's financial health (e.g., by phasing out the true-up over time).

Implementing this reform can be mechanically simple — it only requires removal of the true-up step in a typical FAC. In other words, an estimate of expected fuel costs would be built into rates, but no ex-post true-up to actual expenditures would be made. The expected value to be included in rates would be determined as part of a regular rate case in the same fashion as other rate components, and it would not be updated further until rates are reset.^{xvi} If fuel costs subsequently rise, the utility could cut costs elsewhere or come in for another rate case, and if fuel costs fall, the utility could enjoy additional profits.

Alternatively, a regulator could determine the expected value of fuel costs outside of a full rate case. For example, a special docket could be used to reset the expected fuel cost quarterly or annually, which could then be recovered as a separate rider. This approach could be particularly useful in jurisdictions that employ multiyear rate plans, where typically utilities are expected to stay out of rate cases for three to five years at a time.

^{xvi} If a regulator expects fuel costs to vary seasonally, it could set a seasonal structure for the expected value rather than a single annual number. Automatic escalation based on an external index (e.g., inflation) could also be applied. We are not talking about such automatic adjustments when we refer to rates being “reset” here, but instead to the process of updating the estimate itself.

Key Questions

Some of the key questions that pertain to fuel-cost true-up removal include the following:

How should the expected value be set? As is true under a typical FAC, this policy option requires determining an “expected” level of fuel costs, which is then built into the volumetric component of rates. An important question is how this expected value will be determined and, in particular, whether it will be based on forecasted or historical values. The key drawback to relying on a forecast is that it can open the door to gaming because the utility would benefit financially if it can inflate the forecast. Setting the expected value based on historical data can help avoid this problem.^{xvii} Another way to address this concern would be to use a publicly available commodity forecast (e.g., NYMEX for gas prices).

How often should the expected value be updated? Because this policy option removes the true-up of expected to actual fuel costs, it is important to update the expected value periodically to reflect changing conditions. If the expected value is set as part of a traditional rate case, it could be updated every one to two years along with other rate components. If the regulator opts to set the expected value in an alternative venue (e.g., a special fuel-cost docket), it could update the value as often as desired. Updates that are too frequent are likely to undermine the strength of the cost-containment incentive created by the mechanism, whereas updates that are too far apart could result in unacceptable windfall profits or losses to the utility. The regulator should carefully balance these factors when determining the cadence of updates.

How can the risk of extreme outcomes be reduced? Because actual fuel costs may sometimes be substantially higher or lower than expected when rates are set, a utility operating without a true-up may at times collect substantially more or less than what it spends on fuel. High windfall profits could undermine affordability for customers, whereas substantial losses could threaten the utility’s financial health. To avoid this, the regulator could adopt strategies to protect customers and the utility from extreme outcomes. For example, the regulator could specify particular conditions (e.g., utility profits that rise above a particular threshold) that would automatically trigger a review of the expected fuel-cost value.^{xviii}

Would the utility cut key services if fuel prices spike? If the true-up is removed and fuel costs surge, a utility may cut costs elsewhere in an effort to hit its earnings targets. Although this concern is not unique to fuel costs, a large fuel-price spike could put substantial pressure on the utility to look for savings opportunities. This could lead to spending cuts in important but flexible spending categories like vegetation management, which could cause reliability problems down the road. Regulators could guard against such reactions by taking measures to reduce the risk of extreme outcomes, as discussed previously. They could also consider tracking or incentivizing utility performance in key dimensions that may be affected by spending reductions (e.g., reliability, customer service).

State Examples

At present, no state has removed the fuel-cost true-up. However, this policy was standard practice in every state before FACs became the norm.

xvii This gaming concern is also relevant to fuel-cost sharing, and we examined it in more depth in the section about that policy option. We encourage interested readers to review the more detailed discussion in that section.

xviii This is similar to the “reopener” provisions that are often included in multiyear rate plans.

Fuel-Risk Reduction Tariffs

Utilities could offer new retail tariff options that create an incentive for the utility to reduce fuel costs while simultaneously insulating customers from fuel-cost fluctuations. Such “fuel-risk reduction” tariffs would enable individual customers to avoid some of the risk of fuel-cost volatility. The strength of this incentive would depend on how many customers take service under the new tariffs, which would in turn depend on how many customer classes have access to it and whether it is implemented on an opt-in or opt-out basis.

Fuel-risk reduction tariffs would offer customers the opportunity to lock in a predetermined rate for the fuel-cost component of their bills. If the utility’s actual fuel-cost expenditures differ from the revenues collected through these tariffs, the difference would not be trueed up. In other words, if the utility paid more for fuel than it recovered from customers on the tariff, it would not recover that additional amount, and if it paid less, it would not refund the difference to customers.

Providing a fuel-risk reduction tariff as an option could increase customer choice. For example, such tariffs might appeal to customers who are concerned about volatility and willing to pay a potential premium for increased bill predictability.

Key Questions

The key questions for policymakers interested in developing a fuel-risk reduction tariff include the following:

How should the fuel-risk reduction tariff be structured? Tariffs that shift fuel-cost risk away from retail customers could be structured in different ways. One option is a *fixed-rate* tariff that features a set per-kWh rate for fuel costs. Because the revenues collected via this rate would not be subsequently adjusted to reflect the utility’s actual fuel costs, such a tariff would expose the utility to more fuel-price risk than a traditional FAC. The set per-kWh rate could be time differentiated (e.g., it could differ by time of day or by season), but it would not be adjusted during the period when it is in effect. A fixed-rate tariff would operate similarly to the fuel-cost true-up removal policy option but on an individual customer basis.

Another option is a *flat-charge* tariff that features a monthly charge for fuel costs. Such a tariff could be implemented on a stand-alone basis, or it could be part of a broader subscription rate in which the customer’s entire bill remains the same month to month. A flat-charge tariff could apply the same charge to all customers in a class, or the size of the charge could be based on past consumption levels (e.g., the average number of kWh consumed over the previous year). The second of these options is preferable.

Although applying the same flat charge to all customers would offer maximum predictability to the customer, this approach has some major downsides. Because customers would always pay the same amount regardless of how much electricity they use, they would have no financial incentive to conserve energy, install distributed generation, or shift demand in ways that benefit the grid. Because all of these actions can reduce total system costs, such a tariff could drive up costs for other customers in the short and long term (e.g., higher congestion charges during peak hours, more transmission and distribution system upgrades) and undermine state energy efficiency and emissions-reduction goals. Applying the same flat

charge to all customers would also disproportionately benefit high-usage customers, who on average have higher incomes than low-usage customers. For all of these reasons, applying the same flat charge to all customers is not recommended.

A flat-charge tariff that is instead based on past consumption levels could partly address these issues. For example, if the average number of kWh consumed over the previous year is used to determine the size of the monthly charge, a customer who expects to remain on the tariff will have some incentive to conserve and to install distributed generation.^{xix} Basing the size of the fixed charge on past consumption could also help avoid the subsidization of high-income customers by low-income customers.

Both the fixed-rate and flat-charge options would increase predictability for customers participating in the tariff, which means someone else must bear additional fuel-cost risk. This risk should not be placed on nonparticipating customers (e.g., by increasing the size of the FAC true-up on those customers' bills) because this could raise subsidization concerns and it would also undermine the utility's incentive to contain fuel costs. Instead, the utility should manage the additional risk. The customers participating in the tariff could also be asked to pay a risk premium; this would be incorporated into the tariff and would represent the price the customer must pay for increased predictability.

Should the tariff be opt-in or opt-out? Customer participation in opt-in tariffs tends to be much lower than in opt-out tariffs. Implementing a fuel-risk reduction tariff on an opt-in basis would enable individual customers to reduce their exposure to fuel-cost volatility, while likely keeping the overall financial risk to the utility low. In contrast, implementing the tariff on an opt-out basis would have much broader impacts on both customers and the utility.

How often should customers be allowed to opt in and out of the tariff? Whether the tariff is opt-in or opt-out, it could enable customers to bet on fuel-cost trends, opting in if they think prices will increase and opting out if they think prices will decrease. The risk of such behavior is likely to be greatest among large commercial and industrial customers, but this strategy could be used by any savvy customer. To reduce this risk, regulators could limit how often customers can opt in and out of the tariff.

Which customer classes should be included? The fuel-risk reduction tariff could be offered to a small subset of customers or more broadly. Such tariffs may be of particular interest to those who value stability (e.g., commercial customers), though if customers must pay a premium for that stability, they may be less appropriate for some customer segments (e.g., low-income residential customers). Regulators should also consider whether some customers will need help understanding whether the new tariff makes sense for them, making customer outreach and education necessary.

How should the preset rate or charge for fuel be determined? The per-kWh rate or flat charge for fuel costs can be based on either a forecast or historical values. As with fuel-cost sharing and fuel-cost true-up removal, relying on forecasts could open the door to gaming because if a utility is able to inflate the forecast, the rate and thus collected revenues will increase. Relying on historical values instead (e.g., a five-year rolling average of past fuel costs) can help avoid this problem.

xix The incentive to conserve would be somewhat less under this tariff design than under a fixed-rate tariff because the financial benefit to the customer of saving a kWh would be delayed by up to a year. The incentive to install customer-owned distributed generation would also be somewhat less because customers would still need to pay the upfront cost of the system but would not realize any savings on their bill for some time. Such a tariff could, however, encourage customers who are planning to electrify their home to adopt energy efficiency retrofits the year before, as this would lock in a lower flat charge for their first year of increased consumption due to electrification.

How often should the rate or charge be updated? As fuel costs change over time, the per-kWh rate or flat charge should be changed periodically to reflect updated expectations. These updates could be conducted only through a general rate case (and thus occur on the same schedule as the updates to most other rate components) or they could be performed more frequently through a dedicated proceeding. Less frequent updates could give more certainty to customers enrolled in the tariff about the size of future bills. However, if updates are too infrequent, the tariff could collect more or less revenue than necessary over an extended period, resulting in large windfall gains to the utility (which could undermine affordability) or large losses (which could negatively impact the utility's cash flow). The best schedule for updating the tariff will depend on local factors, such as the utility's fuel mix, the share of customers enrolled in the tariff, and the existing rate-case schedule. Regulators could also put guardrails in place that trigger a review if actual fuel costs deviate sharply enough from expected values.

Would a fuel-risk reduction tariff affect electrification? A fuel-risk reduction tariff would not penalize the utility for greater total fuel usage (as some other policy options discussed in this handbook would), so it would not create a financial incentive for the utility to oppose electrification. On the customer side, a tariff that applies the same flat charge to all customers regardless of usage could even encourage electrification, but there are more efficient, equitable, and direct ways to accomplish this policy goal.^{xx}

State Examples

A number of utilities offer flat-charge-style tariffs. While these may include other cost components besides fuel expenses, they can offer models to regulators interested in designing fuel-risk reduction tariffs.

Oklahoma Gas & Electric (OG&E) is one example. It offers a “guaranteed flat bill” to its residential and small general service customers that features a fixed monthly charge over the course of a year. The level of the charge is based on the individual customer's weather normalized historical usage over 12 to 24 months, as well as an adjustment for expected usage changes over the period. The formula used to calculate the level of the charge includes a risk premium, the impact of which is capped at 10%. If actual usage exceeds expected usage by at least 30% over three months, the utility has the ability to move the customer off the tariff and charge them an early departure fee.¹⁰ In 2021, OG&E experienced a loss from its guaranteed flat bill tariff when winter storm Uri drove up natural gas prices.¹¹

Florida Power & Light (FP&L) also offers a flat-charge tariff to residential and small general service customers. Its FLAT-1 tariff consists of a fixed monthly charge for a period of one year, the size of which is based on the customer's historical consumption normalized for weather and adjusted for changes in customer behavior. The calculation includes a risk premium capped at 5%. FP&L can require a deposit up to twice the estimated average monthly bill to move a customer onto the tariff, and the utility can move the customer off the tariff and charge a removal fee if their consumption exceeds expectations by 30% for three months.¹²

xx As discussed previously, applying the same fixed charge to all customers would diminish customers' financial incentive to conserve electricity. This would encourage customers to electrify but not in an efficient manner, which could unnecessarily drive up overall system costs. Also, not all customers would be equally positioned to act on a tariff-based electrification incentive. For instance, renters may not have the power to make upgrades to their residences, and low-income customers may not have the ability to purchase electric vehicles. Other types of programs (e.g., rebates for building owners, electrification of public transit) may be more effective electrification strategies than retail tariffs for these customers.



Duke Energy Indiana offers a flat-charge tariff to a limited number of residential customers with load profiles that “can be modeled with reasonable predictability.” The size of the monthly charge under the Your FixedBill tariff is calculated based on 12 or more months of past usage data, normalized for weather, and subject to a usage adjustment (this adder is capped at 3.6% for the first year the customer is on the tariff and 0.8% after that). The formula used to calculate the charge can include a risk premium (called a program fee) of up to 9%. Duke can send letters warning the customer of excess usage, and if after two such letters the customer’s usage is 15% greater than expected for any month, the utility can reprice the monthly charge based on updated usage information. If the customer does not accept the new amount they are removed from the Your FixedBill tariff and charged a \$50 administration fee.¹³

In states that have opened the electricity market to retail competition, various fixed-rate plans are available to customers. These could also serve as examples for fuel-risk reduction tariffs adopted for regulated utilities that feature a fixed-rate design.

Planning and Procurement

A variety of updates to planning and procurement processes could help reduce utilities' reliance on costly and price-volatile fuels. Updating long-term planning and procurement methods can reduce utility reliance on fuels over time (and thus the need to recover fuel costs from customers). Shorter-term strategies, meanwhile, can focus utility attention on careful fuel-cost management and limit the impact of fuel-price volatility on customer bills. A number of key reforms that regulators could consider are explored below.

Long-term planning. Changes to long-term resource planning requirements can play a large role in shifting the utility's portfolio away from price-volatile fuels over time. Such reforms can take a variety of shapes. Many, but not all, states conduct resource planning, though there is plenty of room for improvement in how those resource plans are conducted, reviewed, and approved.¹⁴

Regulators could direct the utility to fully consider cost-effective demand-side resources (e.g., energy efficiency, demand flexibility) during portfolio creation and to treat them as supply-side resources rather than as reductions in demand during modeling. Regulators could also mandate the inclusion of specific portfolio types (e.g., fuel-free portfolios) in the utility's analysis, and they could require more robust analysis of fuel-price volatility in the utility's resource plans. Regulators could also empower stakeholders to scrutinize the utility's modeling choices and propose their own portfolios, such as by requiring the utility to run new models based on stakeholder-provided inputs or requiring the company to make its modeling data, assumptions, and software available to stakeholders.^{xxi}

Scrutiny of fuel-price projections. Regulators should also change how price-volatile fuels like natural gas are considered during the planning process. This could be accomplished through increased scrutiny of gas-price forecasts and their underlying assumptions and by requiring the utility to run high gas-price sensitivities for all portfolios. Commissions should also direct utilities to conduct more sophisticated analyses (e.g., stochastic analyses) to reveal potential cost impacts under a variety of converging conditions (e.g., fuel-price spikes, heat waves, supply disruptions).

Regulators should also ensure that the fuel-price forecasts used across proceedings are consistent. A utility should not be permitted to use a low gas-price forecast when planning new generation resources and a higher forecast to set the expected value for a fuel-cost sharing mechanism. As another example of how the fuel-cost assumptions used in planning could be improved, regulators could require that new fuel-related infrastructure proposals (e.g., gas-fired plants and pipelines) be presented with realistic service lives that are in line with state climate goals. For example, regulators could choose not to permit a utility to propose a 30-year lifetime for a new gas plant in a state with a zero-by-2050 policy goal.

xxi For example, one expert recommends that the utility provide: (1) the entire modeling database in a format readable without a model license; (2) a well-documented manual detailing the logic of the model, defining the inputs and outputs, and providing guidance on its use; and (3) the ability to license the model at a reasonable cost if a license is not otherwise provided by the utility. See William Driscoll, "States Could Save Consumers Billions with Solar, by Requiring Transparent Utility Modeling," *PV Magazine*, September 9, 2019, <https://pv-magazine-usa.com/2019/09/09/states-could-save-consumers-billions-with-solar-by-requiring-transparent-utility-modeling/>.

Locking in forecasts for new generation. If a utility expects to bear some of the financial risk of fuel-cost volatility, it will be inclined to do the most robust possible planning to account for the price volatility of fuels. Regulators can build a reasonable level of risk exposure into the planning process by requiring that all new generation be subject to fuel-cost sharing. Commissions could also consider locking in the price forecast used at the time of approval as the baseline (i.e., the expected value) used by the fuel-cost sharing mechanism.^{xxii}

All-source solicitation and procurement. Long-term planning is often based on resource-specific assumptions, and then the resources selected are procured as a separate step later. The resource-selection process is highly sensitive to the input assumptions, so if those assumptions are unrealistic (e.g., fuel prices that are too low) or limited (e.g., distributed resources are not considered), this can create a bias toward selecting traditional, fuel-based resources.¹⁵ Procurement processes can also favor traditional solutions when they invite bids for specific resources rather than system needs. Updating these processes can result in increased selection of fuel-free generation and demand-side resources.

Regulators should mandate the use of all-source solicitation and procurement as a means of removing the bias against fuel-free resources. All-source solicitation and procurement involves defining the utility's needs (e.g., energy, capacity, flexibility services) and then inviting bids for any technologies that can meet those needs. The submitted bids can be used to represent the options available during the planning process, and they can also serve as the basis for subsequent procurement decisions.¹⁶ To ensure all proposals can compete fairly, the fuel-price risk associated with different resources should be carefully considered when selecting between them.¹⁷

Fuel management plans. Fuel management plans encourage utilities to focus more on fuel-cost management, and they also better position regulators to determine whether the fuel costs that utilities later present for recovery were prudently incurred. These plans can require the utility to articulate its fuel procurement plans, predict fuel-cost outcomes under different possible scenarios (e.g., severe weather events, supply-chain disruptions), and explain its risk management strategies. To ensure that plans are of high quality, they should be subject to regulatory review and approval. Moreover, plan sponsors should be subject to discovery and cross-examination, and stakeholders should have opportunities to review and provide input on plans through filed comments, public hearings, and responsive testimony.

Hedging. Hedging refers to the use of financial instruments to mitigate risk. Used by utilities to reduce the impact of fuel-price volatility on customer bills, hedging can be thought of like insurance where premiums are paid to prevent high-price outcomes. When done correctly, hedging can provide stability and savings, but if done improperly, it can result in unnecessary costs. Some hedging arrangements require a monthly or annual fee in exchange for a cap on prices. Others lock in a predetermined price and amount of fuel to be purchased at a future date, which insulates the off-taker from market price volatility. Many utilities use hedging to some extent, but in many jurisdictions it is subject to little or no review.

Regulators interested in reforming hedging should review current practices and consider whether any changes are needed to better serve customer interests. However, many commissions do not have staff with sufficient experience or expertise in hedging to fully examine the risks and benefits of particular hedging agreements. In those cases, oversight of hedging practices could be folded into the fuel management plans described above.

^{xxii} This idea was also discussed in relation to the fuel-cost sharing policy option, on [page 12](#).

Key Questions

Given the variety of possible updates to planning and procurement processes, the questions regulators face will depend on the reforms they are considering. However, they may include the following:

How should utility bids be treated during all-source solicitation and procurement? To obtain the best outcomes, all-source solicitation and procurement processes should create a level playing field for all proposals. However, if the utility is responsible for choosing between bids, it may favor its own submissions (or those of its affiliates) over the bids of third parties. Regulators can prevent this by not allowing the utility (or its affiliates) to submit bids, or if they do allow the utility to submit proposals, they can take steps to ensure that all proposals are fairly evaluated.¹⁸ One way to accomplish that would be to require the use of both an independent consultant to draft the request for proposals (with no input from any utility division that could submit a bid) and an independent evaluator to assess the proposals received.

Is hedging worth the additional cost? Like any insurance, hedging needs to be used carefully to cost-effectively protect against volatile fuel prices. Hedging is not guaranteed to be cost-effective, and it could be imprudently procured. Evaluating fuel hedging through independent audits and regularly reviewing the performance of hedging instruments are key.

Should resource and system planning processes be coordinated? Because long-term resource planning focuses on the resources that will be needed to meet demand, reforming these processes represents a key opportunity to reduce utility reliance on costly and price-volatile fuels. However, the physical configuration of the transmission and distribution system also matters because this determines which fuel-free resources can actually be used and how much flexibility there is to substitute between them. Closer coordination between resource planning and system planning processes can enable better optimization of the overall system to enable demand to be reliably and affordably met with less fuel.

State Examples

Various states have planning and procurement policies in place that can serve as examples for other regulators. For example, **Indiana** requires utilities to evaluate demand-side resources “on a consistent and comparable basis” with supply-side resources during the planning process, including consideration of the resources’ risk and cost-effectiveness.¹⁹ In **New Mexico**, when regulators granted stakeholders access to utility modeling, they enabled stakeholders to propose alternative resource portfolios to replace a retiring coal plant. The result was that the commission adopted an entirely fuel-free portfolio identified by stakeholders, rather than the option preferred by Public Service Company of New Mexico (which had included new natural gas-fired generation).²⁰ Meanwhile, the use of all-source solicitation and procurement in **Colorado** produced third-party bids with what Public Service Company of Colorado described as “shockingly” low wind and solar prices.²¹

Strategies to Increase Access to Information

A central reason why traditional FACs create suboptimal outcomes concerns access to information. Utilities generally have better access to information than their regulators do, and because of this “information asymmetry,” it can be difficult for regulators to determine whether the fuel costs presented for recovery through a FAC are unnecessarily high. For example, the regulator may not be able to tell if a utility is using its better contracts to supply competitive markets and dumping its inferior ones on customers.

Strategies to improve information access can support sound fuel-cost management in multiple ways. Where another fuel-cost reform has been implemented, greater access to information can help the regulator understand how well that policy is working and whether additional changes are merited. Strategies that improve information access can also be beneficial on their own because they can help regulators better administer the FAC policies that remain in place in most of the United States.

A variety of strategies could enhance regulators’ and stakeholders’ access to information. Four of the most promising in relation to fuel costs are discussed below.

More transparent fuel-supply contract terms. In many states today, utilities are allowed to treat their fuel-supply contracts as trade secrets, which prevents customers and other stakeholders from evaluating whether they are reasonable. When advocates and other stakeholders are barred from accessing key documents, they cannot identify potential prudence issues and flag them for the commission to consider. Regulators could increase transparency by requiring utilities to publicly disclose the key terms of these contracts (e.g., minimum delivery amounts, automatic pricing adjustments, changes in the scope of utility and vendor responsibilities).

Enhanced prudence reviews. In many states, fuel-cost recovery proceedings are limited in scope and subject to tight timelines. As a result, fuel costs are often approved for recovery after only a superficial prudence review. Regulators could reform these proceedings to enable enhanced scrutiny. Regulators can strengthen the minimum filing requirements to shift the burden of proof onto the utility requesting cost recovery, while simultaneously demonstrating a willingness to disallow recovery if the utility cannot convincingly demonstrate prudence. For this strategy to be effective, it must be clear to the utility that disallowance is a real and substantive risk. Simply applying a slightly higher level of review to an existing, cursory process is unlikely to be successful.

Regular audits. Audits by an independent third party can give regulators, customers, and stakeholders better visibility into a utility’s performance, including its fuel-cost management, fuel procurement practices, and risk-reduction strategies. Requiring both a management audit and a financial audit on an annual basis would be beneficial.

The financial audit provides insight into how the utility has been spending money. This audit would enable both the regulator and stakeholders to better judge whether its fuel purchases have been prudent.

The management audit may be a substantially longer document. It could include detailed information across multiple dimensions (e.g., how much natural gas is purchased through short-term versus long-

term contracts, the origins of purchased coal, contract terms and conditions). It can also include auditor recommendations (e.g., that the utility take specific steps to ensure gas plants remain operational during cold weather, that the utility purchase more power through power-purchase agreements to reduce uneconomic fuel purchases). The management audit can enable stakeholders to access important information without the need for lengthy discovery processes, and the auditor's recommendations can shape regulatory decisions.

Regulators should require the sponsors of audits to be subject to discovery and cross-examination in relevant dockets. Audit parameters should also be clearly defined to provide clarity in priority areas of performance and to enable comparison with industry peers.

Broader and deeper stakeholder engagement. Robust stakeholder engagement in proceedings where fuel-cost recovery is considered can help regulators access and analyze the information they need to make sound decisions. Where commission staff have limited capacity to dig into utility fuel-cost filings, stakeholders can help identify inconsistencies and potential prudence concerns. Enabling stakeholders to offer their own proposals for changes (rather than being limited to reacting to utility proposals) can also help surface new solutions. Finally, stakeholder responses in dockets that point out issues related to fuel-cost recovery can help build a library of information that other stakeholders and regulators (both within and outside the state) can later use to improve policies.

Strategies to enhance stakeholder engagement include restructuring proceedings to allow more time for stakeholders to provide input, ensuring ample opportunities for discovery and cross-examination, and equipping stakeholders with the resources they need to engage meaningfully (e.g., automatic access to key information such as via management audits, intervenor compensation to enable less well-resourced stakeholders to participate). Regulators could also solicit input from previously underrepresented constituencies and increase the participatory nature of commission processes (e.g., informal solution-finding workshops in addition to formal litigated processes).

Key Questions

The key questions regulators will face depend on which strategies they choose to pursue to increase information access. However, such questions will likely include the following:

Will additional effort be required from regulators and stakeholders? As with any reform, the amount of effort that a reform will demand is important to consider. Enhanced prudence reviews are likely to increase the demands on regulators and their staff, who may already be heavily burdened by existing work. In addition, strengthening stakeholder engagement could require devoting regulatory resources to educating parties who are not familiar with existing policies or processes. However, there are often multiple ways to accomplish the same goal, and regulators can consider whether there are alternatives that reduce the needed effort. The time that commission staff and stakeholders must devote to discovery requests can be reduced by using regular financial and management audits, as well as by requiring the utility to automatically disclose key data, models, and documents during enhanced prudence reviews.

Will additional time be needed to reach decisions? Some strategies to increase access to information may require additional time. Enhanced prudence reviews may take longer than current prudence reviews, and establishing robust stakeholder engagement in a fuel-cost recovery proceeding may require comment periods to be lengthened, public hearings to be added, or outreach to be conducted to specific

constituencies. If additional time is needed, regulators should consider how processes can be changed to accommodate this. For example, conducting fuel-cost recovery proceedings less frequently could offset the increased time it takes for an enhanced prudence review during each proceeding.

How should sensitive information be handled? Though greater disclosure of utility fuel-supply contract terms, data, models, and other information could be beneficial, some information is sensitive and should be disclosed selectively. Regulators should consider whether any part of a fuel-supply contract should remain confidential, and if so, a nondisclosure agreement should be required for stakeholders to access it. Utilities may wish to keep certain data as a trade secret so it cannot be accessed by competitors, but regulators should consider whether this is appropriate for a utility that functions as a regulated monopoly (and which therefore does not face direct competition).

What will be the cost to customers? Some strategies to increase information access involve costs that are ultimately born by customers. Audits require substantial time and effort from both the third parties conducting them and the utilities subject to them, while achieving robust stakeholder engagement may require that intervenor compensation be provided to less well-resourced parties. As with any reform, it is the regulator's responsibility to determine whether the incremental costs of a reform outweigh the benefits the reform is likely to provide.

State Examples

A number of states have policies that support increased access to information. One is **Kentucky**, which requires utilities to file copies of all fuel-supply contracts (including any modifications and related documents) promptly, to justify in writing any purchases from utility-controlled sources, and to also justify any price-escalation clauses. Kentucky then makes all these documents available for public inspection.²²

Ohio regulators recently required independent performance audits of extra customer charges that were collected by three utilities buying power from coal-fired power plants (often at above-market prices), and regulators then solicited stakeholder comments on the auditors' findings.²³

Minnesota also requires utilities to submit an independent auditor's report every year evaluating the previous year's automatic fuel-cost adjustments, though regulators' ability to choose not to approve the auditor's report is limited.²⁴

States also have taken steps to broaden and deepen stakeholder engagement.^{xxiii} In a recent distribution system planning proceeding, **Oregon** conducted stakeholder education, structured the proceeding in ways that facilitated stakeholder input, and provided less formal venues (e.g., workshops) for engagement. In **Michigan**, the MI Power Grid initiative has engaged hundreds of diverse stakeholders through more than 50 meetings, including representatives of local communities, environmental justice organizations, and consumer advocates. Also, **at least 16 states** offer intervenor compensation to support stakeholders' ability to engage in regulatory proceedings.^{xxiv}

xxiii For more information about all the state examples discussed in this paragraph, see Cory Felder, Jessie Ciulla, Rachel Gold, and Jacob Becker, *Regulatory Process Design for Decarbonization, Equity, and Innovation*, RMI, 2022, <https://rmi.org/insight/puc-modernization-issue-briefs/>.

xxiv These 16 states are Alaska, California, Colorado, Hawaii, Idaho, Illinois, Kansas, Maine, Michigan, Minnesota, New Hampshire, Oregon, Tennessee, Washington, West Virginia, and Wisconsin.

Efficiency Ratio

As detailed previously, reforms designed to share fuel-cost risk between utilities and their customers is an emerging policy space in which most US states have limited experience. We anticipate that decision makers will develop a range of new policy proposals in the coming years as fuel-cost volatility, advances in fuel-free technologies and demand management strategies, and continued social inequities push them to reevaluate the wisdom of existing FAC policies.

One such emerging idea is implementing a PIM to encourage the utility to reduce the cost of producing a MWh of power. A PIM is a regulatory tool that ties a portion of a utility's earnings to a desired outcome, which is measured by a specific metric. In this case, the metric is the utility's production cost efficiency measured in \$/MWh, so we refer to this type of PIM as an "efficiency ratio." The \$/MWh metric could focus narrowly on the utility's own fuel expenditures, or it could include purchased power and represent the utility's net power costs.

To be effective, an efficiency ratio PIM must not only measure the utility's production cost efficiency today but also indicate whether the metric has improved or declined over time. To accomplish this, the historical value of the metric (e.g., the utility's historical per-MWh fuel costs) is compared with the metric's current value. If the utility's \$/MWh has decreased, its production cost efficiency has improved and the company would be eligible for a financial incentive under the mechanism. Conversely, if the \$/MWh has increased, its production cost efficiency has declined and the company may be subject to a penalty.

The financial reward or penalty under a PIM can be structured in various ways. An efficiency ratio is no exception; while by definition an efficiency ratio must employ a \$/MWh metric, regulators have the flexibility to select from a range of possible incentive structures. These possibilities include a constant marginal incentive (e.g., the utility earns the same reward for each incremental improvement in the metric), a lump sum (e.g., the utility earns a fixed reward if its performance exceeds a specific threshold), and more complex designs (e.g., a banded design in which the marginal or lump-sum incentive changes multiple times as the utility's performance crosses different thresholds).

Another possibility is to use the \$/MWh metric to implement a usage-normalized version of fuel-cost sharing. In this approach, the improvement (or decline) in the value of the \$/MWh metric would be multiplied by the total MWh from a reference period. For example, using the MWh expected under "normal" weather conditions as the multiplier would result in a weather normalization. Under this PIM, if the actual weather conditions were "normal" over the time period, the financial impact on the utility would be the same as a fuel-cost sharing policy — but if a heat wave caused usage to skyrocket, the utility would not be penalized for the resulting increase in fuel costs.

In addition to the structure of the financial incentive, regulators must also consider its magnitude. Ideally the incentive should be large enough to motivate the utility to achieve the policy goal, but no larger since excessive rewards unnecessarily burden customers and excessive penalties could negatively impact the utility's financial health. If both financial incentives and penalties are used, the commission must also consider whether these should be symmetrical or asymmetrical.

Regulators could design the efficiency ratio to apply to all power generated by the utility (i.e., a single \$/MWh metric could be used) or separately to different categories of power (e.g., the \$/MWh could be tracked and incentivized separately by fuel type). Regulators may also wish to apply the efficiency ratio to purchased power to avoid encouraging the utility to make uneconomic substitutions between purchases and its own generation (e.g., generating more electricity when fuel prices fall even if power could be purchased from third parties more cheaply).

Regulators should also consider how different factors may impact the \$/MWh metric. For instance, although an improvement in the metric may reflect improvements in the utility's fuel-cost management, such improvement could also be due to factors outside the utility's control (e.g., general market conditions) or utility actions that run counter to policy goals (e.g., running an aging coal plant more to decrease the heat rate, reduce the \$/MWh, and earn a larger reward under a coal-specific efficiency ratio). Commissions may therefore wish to apply additional tests that require the utility to show that any \$/MWh reductions were the result of its own appropriate actions before allowing it to receive an incentive payment. Regulators could also consider adjusting penalties if the utility can convincingly demonstrate that a deterioration in the metric was due to no fault of its own.

Potential Benefits and Drawbacks

As a new policy option, the key benefits and drawbacks associated with the efficiency ratio are still emerging. However, the following considerations may be relevant.

One benefit is that if the \$/MWh metric is restricted to the utility's own fuel costs, it is straightforward to calculate. Since all vertically integrated, investor-owned utilities report historical data on fuel costs and generation to federal agencies (e.g., the Energy Information Administration, the Environmental Protection Agency), there is no need for fuel-cost forecasting. However, if additional costs are included in the metric (e.g., the fuel costs in purchased power, other variable operating expenses deemed part of the net power cost), these data may not be as readily available, and in some cases they may require estimation.

Furthermore, utilities may be more supportive of the idea of an efficiency ratio PIM than other policy options. Thus far, the efficiency metric concept has sparked greater engagement from utilities in states considering action by commissions or legislatures.^{xxv}

xxv This is based on informal conversations that some of the authors have had about fuel-cost management options with state legislators, commissioners, consumer advocates, and utility representatives.

However, the efficiency ratio concept also has certain drawbacks. One is that focusing on \$/MWh may not advance other policy objectives. A utility could reduce the \$/MWh ratio by either reducing the numerator (cost) or increasing the denominator (electricity production). However, tactics to increase the total electricity production may not be in the public interest.^{xxvi} For instance, a utility could “improve” the \$/MWh metric by declining to pursue opportunities to conserve energy during hours when costs are below average.^{xxvii} The effects of this drawback are limited somewhat by the fact that in the next period the lower \$/MWh value becomes the new benchmark.

An efficiency ratio applied separately to different categories of power (e.g., one that tracks the \$/MWh by fuel type) could create additional challenges. For instance, if the PIM rewards the utility for reducing its per-MWh cost of generating power from natural gas, a drop in natural gas prices could enable the utility to earn a reward for each additional MWh it can generate from that fuel — even if this means curtailing more cost-effective resources (e.g., wind, solar). This could result in both higher costs to customers and higher carbon emissions. An efficiency ratio applied separately to different categories of power could also create an incentive to run coal units at higher capacity factors to increase plant efficiency (i.e., to decrease the heat rate), something entirely within the utilities’ control.

Further Development

As the efficiency ratio is an emerging idea, its benefits and drawbacks have not been fully explored. As with any novel policy, regulators interested in this concept should investigate its potential impacts carefully. The design and implementation of any efficiency ratio should also include robust engagement with utilities, consumer advocates, trade associations, and other relevant stakeholders.

xxvi A financial incentive to sell more electricity is called a throughput incentive. Since a throughput incentive tends to undermine utility support for energy efficiency programs, many states have taken steps to combat the throughput incentive created by traditional ratemaking. Such policy actions include revenue decoupling and PIMs focused on energy efficiency programs. Regulators in states that have energy efficiency as a policy goal may wish to consider whether additional actions are merited to address any throughput incentive created by an efficiency ratio.

xxvii If a utility’s per-MWh costs are substantially higher in a few hours of the day or year, most hours of the year may in fact fall into the “below-average cost” category. For example, in the late afternoon a certain utility may need to bring more costly gas plants online to meet its daily peak — and its per-MWh cost may rise further during a few hot summer afternoons when air conditioning usage is peaking, wholesale electricity prices are spiking, and the utility must purchase additional power to meet its customers’ needs. A few very costly hours can push the average \$/MWh well above the median, with the result that the majority of hours have costs that are below average.

Conclusion

The traditional FAC policies that are common across the United States give electric utilities little incentive to carefully manage their fuel costs. Under a FAC, customers, rather than the utility, pay for excessive fuel expenditures, and if the utility reduces its fuel costs, it does not benefit. Given the impact that fuel has on both customer bills and carbon emissions, it is worth considering alternatives to the traditional FAC.

When the wisdom of FACs is called into question, utilities often defend these policies by arguing that they have no control over fuel costs. However, this was never entirely the case, and it is even less true today. Thanks to technological advances, utilities are in a better position to manage their fuel costs now than ever before. This is true on both the supply side (e.g., cost-effective renewables, battery storage) and on the demand side (e.g., time-of-use rates, virtual power plants).

Because of these developments, considering alternatives to traditional FACs is particularly timely — and we encourage regulators to explore the options available to them. This handbook is intended as a resource to support these discussions.



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RMI Innovation Center

22830 Two Rivers Road
Basalt, CO 81621

www.rmi.org

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BEFORE
THE GEORGIA PUBLIC SERVICE COMMISSION OF
DOCKET NO. 56765

In re:

Georgia Power Company's Fuel Cost
Recovery (FCR-27)

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the Direct Testimony of Jeremy Kaldin on behalf of Sierra Club, NRDC, and SACE has been furnished by electronic mail on this 9th day of April, to the following:

Sallie Tanner

Executive Secretary
Georgia Public Service Comm.
244 Washington Street, SW
Atlanta, GA 30334
stanner@psc.state.ga.us

Jeffry C. Pollock

J. Pollock Incorporated
14323 South Outer 40 Road,
Suite 206 N
Town and Country, Missouri 63017-5734
jcp@pollockinc.com

Jeremiah Haswell

Kyle Leach

Georgia Power Company
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374
jhaswell@southernco.com
kleach@southernco.com

Robert Trokey

Justin Pawluk

Chris Collado

Tom Newsome

Jamie Barber

Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334
rtrokey@psc.ga.gov
jpawluk@psc.ga.gov
ccollado@psc.ga.gov
tnewsome@psc.ga.gov
jamieb@psc.ga.gov

Jennifer Whitfield

Amitav Kamani

Bob Sherrier

Alyssa Krantz

Southern Environmental Law Center
Ten 10th Street, NW, Suite 1050
Atlanta, GA 30309
jwhitfield@selc.org
akamani@selc.org
bsherrier@selc.org
akrantz@selc.org

Brandon F. Marzo

Steven Hewitson

Allison W. Pryor

Troutman Pepper Hamilton Sanders LLP

600 Peachtree Street NE, Suite 3000

Atlanta, GA 30308-2216

brandon.marzo@troutmansanders.com

steven.hewitson@troutman.com

allison.pryor@troutman.com

Charles B. Jones, III

Jim Kelleher

Georgia Association of Manufacturers 75

Fifth Street, NW

Suite 3412

Atlanta, GA 30308

cjones@gamfg.org

jkelleher@gamfg.org

Robert B. Baker

Robert B. Baker, PC

2480 Briarcliff Road, NE, Suite 6

Atlanta, Georgia 30329-3008

bobby@robertbbaker.com

/s/ Caden Koontz

Caden Koontz

Sierra Club

50 F St. NW, Eighth Floor

Washington, DC 20001

(202) 650-6075

caden.koontz@sierraclub.org

1 (The documents referred to were marked for
2 identification as SIERRA CLUB/SACE/NRDC Exhibits 1
3 through 11.)

4 Q. Mr. Goggin, could you please summarize your
5 prefiled testimony.

6 A. Yes.

7 MR. GOGGIN: The crux of my testimony is
8 analysis that identifies \$152 million of ratepayer
9 net losses due to the uneconomic dispatch of the
10 Bowen and Scherer coal plants through the end of
11 February 2026, during the historical period for
12 which Georgia Power seeks recovery in this case.
13 These losses occurred because the company
14 uneconomically dispatched these units, even though
15 the company's own data show lower-cost resources
16 were available in the day-ahead time frame when the
17 company committed the unit to run the next day.

18 These total ratepayer losses represent net
19 losses after factoring in startup costs and other
20 costs in the counterfactual case; wherein, the unit
21 was shut down and then restarted when system
22 marginal costs were high enough to economically
23 justify its operation, instead of remaining online.

24 I respectfully recommend that the Commission
25 disallow recovery of the \$152 million in net losses

1 that occurred because of the imprudent dispatch
2 decisions for the company's coal fleet. This will
3 protect ratepayers from shouldering these
4 imprudently incurred costs and, more importantly,
5 will incentivize the company to avoid uneconomic
6 dispatch going forward.

7 The next section of my testimony then reviews
8 a variety of factors that drive uneconomic dispatch
9 and recommends solutions to reduce or eliminate
10 these factors going forward. Specifically, the
11 Commission should direct the company to remove
12 persistent biases in the inputs into the commitment
13 and dispatch software to result that suboptimal
14 dispatch.

15 I also recommend that the Commission direct
16 the company to not sign coal supply and
17 transportation contracts that include penalties for
18 failing to meet minimum fuel delivery quantities.
19 Those contract terms appear to have been a primary
20 cause of the company running coal plants even when
21 they were not economic, resulting in their
22 excessive and costly operation. In future fuel
23 cost recovery cases, the Commission should also
24 review new or extended fuel supply or
25 transportation contracts to ensure they do not

1 include penalties associated with minimum fuel
2 delivery quantities.

3 Staff also flagged concerns that coal
4 inventory management was causing coal units to be
5 uneconomically dispatched, as we've heard in the
6 previous panel. They note that the coal inventory
7 swelled during the historical period, which
8 corresponds with the period when gas had a lower
9 price, and, thus, was more economic than coal
10 generation in many parts of that period. Normally
11 cheap gas would benefit ratepayers, but minimum
12 delivery requirements in coal transportation
13 contracts forced the coal units to run to burn coal
14 when they are more expensive that -- even when they
15 are more expensive than gas.

16 Staff notes that the company was not
17 responsive to data requests regarding this, but my
18 analysis shows that there was -- and demonstrates
19 that there was significant uneconomic dispatch of
20 coal units during this period. I understand that
21 coal suppliers and transportation companies use
22 these minimum delivery requirements and associated
23 penalties to ensure they recover the significant
24 fixed costs associated with serving a contract if
25 delivery quantities are low. The obvious solution

1 is to recover these fixed costs through fixed cost
2 payments, instead of through variable cost payments
3 with minimum delivery requirements and penalties.

4 That should be acceptable or even preferable
5 to the counterparty as there is less risk of
6 under-recovering fixed cost if volumes are low, but
7 above the minimum delivery requirement. Removing
8 minimum delivery requirements is essential because
9 this appears to have been a primary cause of the
10 uneconomic coal generation. Basically, the company
11 was burning coal to keep coal piles within our --
12 within physical limits and avoid the penalties.

13 In rebuttal, the company attempts several
14 arguments against my analysis that identified the
15 \$152 million in net ratepayer losses. First, they
16 offer the red herring that my analysis did not
17 account for coal unit minimum downtimes. Minimum
18 downtimes do not affect the results of the analysis
19 as all coal unit shutdowns identified in the
20 counterfactual analysis were longer than typical
21 coal unit minimum downtime requirements. And I
22 confirmed this in subsequent analysis after the
23 company filed its rebuttal testimony.

24 My analysis did not just include minimum
25 uptimes, as the company states, but also included

1 startup times and costs, the important parameters
2 for evaluating the prudence of its commitment
3 decisions.

4 Finally, the company argues I did not account
5 for the need to dispatch coal generation to meet
6 transmission reliability or environmental
7 constraints. Regarding transmission reliability,
8 the company uses must-run commitments when it
9 claimed transmission constraints required it to run
10 those units.

11 Our analysis conservatively took the company
12 at its word and assumed that all must-run
13 commitments were reasonable because the company did
14 not provide sufficient evidence to determine
15 whether they were. So this factor does not affect
16 our analysis and identified \$152 million because we
17 gave the company the benefit of the doubt and
18 excluded all transmission-related commitments from
19 our analysis. In my testimony, I calculated costs
20 associated with transmission constraints as a
21 separate additional amount, and you can see that in
22 my testimony.

23 Regarding environmental limitations, my
24 analysis solution of shutting the unit down when it
25 is not economic would solve that constraint by

1 non-emitting. We also accounted for startup time
2 and cost in the analysis and we were -- when we
3 were constructing this analysis and that addresses
4 and should fully incorporate the need to start up
5 plant pollution controls and maintain them at
6 operating conditions.

7 Finally, I review how the company is
8 increasing its dependence on gas duration and how
9 that exposes the ratepayers to excessive costs and
10 risks. As a notable example, the company's gas
11 generators imposed massive fuel costs on ratepayers
12 during the two weeks of Winter Storm Fern earlier
13 this year. And that number is identified in the
14 confidential part of my testimony.

15 I recommend solutions that would better
16 protect ratepayers from those costs and risks than
17 the company's proposal to expand financial hedges,
18 which already impose an exorbitant cost on
19 ratepayers while providing little value. I
20 recommend that the Commission implement a fuel-cost
21 sharing mechanism to incentivize the company to
22 more effectively manage gas price risk and account
23 for the risks of gas price volatility and
24 uncertainty when weighing the prudence of the
25 company increasing its dependence on gas

1 generation.

2 Thank you.

3 MS. ARIZA: Thank you, Mr. Goggin.

4 BY MS. ARIZA:

5 Q. Now, Mr. Kalin, would you please summarize
6 your testimony.

7 A. (Witness Kalin) Yes.

8 MR. KALIN: Good afternoon or evening, I
9 guess, Commissioners. Appreciate your patience and
10 endurance.

11 I'm Jeremy Kalin. I'm an energy finance and
12 investment attorney. That's the bulk of my
13 practice. But on the policy front for the past
14 several years, I've been working across the country
15 with stakeholders of all sorts to develop more
16 appropriate fuel cost recovery mechanisms for
17 electric utilities, including here in Georgia in
18 the FCR-26 docket.

19 I'm a coauthor of two of the more in-depth
20 papers on the topic of -- of recent times. The
21 first was provided to the Commission in 2023. And
22 I think Mr. Lin may have included that as an
23 exhibit to his testimony. And the second is
24 included -- which is a more in-depth paper
25 targeting regulator audiences that you might find

1 quite interesting, included as an exhibit to my
2 written testimony in this docket.

3 In this work, looking at these fuel cost
4 recovery policies, I've come to see that Georgia
5 Commission's treatment of 100 percent pass-through
6 currently of utility fuel costs is the classic
7 example of what is known economically as this moral
8 hazard, where the utility decides how, when, where,
9 how much, from whom, and for how much fuels are
10 purchased for generating electricity, but the
11 utility is completely insulated from the costs, the
12 risks, and the price volatility of those purchases.

13 It's a classic market distortion of a moral
14 hazard because, instead, ratepayers bear that cost,
15 the burden, and the impact of the fuel. And that's
16 everyone from senior citizens on fixed incomes to
17 small businesses and local governments. And to the
18 extent I think we're further deliberating today,
19 the largest industrial users.

20 And I want to look at how we got here because
21 it wasn't always this way. Since the very first
22 utility regulation, utilities had been responsible
23 for managing 100 percent of those fuel costs and
24 fuel risks than during each of the two world wars,
25 when we had worldwide persistent supply

1 disruptions. The utilities requested and were
2 granted temporary insulation from fuel -- fuel
3 price risk and volatility.

4 They were momentarily -- these fuel costs
5 were momentarily passed along to customers,
6 understandably in times of global armed conflict
7 and severe rationing. I think we don't want to
8 visit that kind of rationing again.

9 Then when peacetime stability resumed,
10 utilities again were charged with managing all of
11 the fuel purchasing costs and risks. These fuel
12 costs were the responsibility of utilities and they
13 were reviewed and deliberated extensively during
14 rate case proceedings. Imagine, as we've
15 discussed, adding that to -- to those -- to the
16 integrated resource plans and rate cases, but
17 that's -- that was the reality.

18 And in the mid-1970s, with OPEC's disruption
19 of the global markets, the discussion across
20 Commissions, state legislatures -- and I was
21 surprised to learn even this week, multi-day
22 hearings in Congress on fuel cost recovery really
23 focused on the administrative burden of having to
24 frequently reevaluate these utility under-recovery
25 of fuel costs.

1 So I just want to highlight this. These
2 1970s era first fuel adjustment clauses, they
3 provided utilities with a full pass-through of fuel
4 cost increases -- not all fuel costs. Fuel costs
5 increases -- to ratepayers and only in between rate
6 cases. In some ways, it's sort of like a limited
7 IFR is the way to -- to think about it.

8 And I think it's in this light that the
9 Commission should carefully read the state's --
10 Georgia's fuel cost recovery statute enacted in
11 1979. Specifically, the statute requires the
12 utility to propose, quote, Base rate tariffs to
13 recover fuel costs, end quote. It does not require
14 the utility to recover all of the fuel costs. And
15 the Commission only needs to, quote, Issue an order
16 stating the base rates to be used by the utility,
17 end quote, for fuel cost recovery.

18 As laid out in my written testimony presented
19 already, on multiple occasions the Commission has
20 actually reduced the proposed fuel cost recovery
21 tariff. Implicitly, the Commission has recognized
22 that the statute gives you latitude. In this
23 docket, Georgia Power's application for an amended
24 IFR, and in so many other fuel cost recovery
25 dockets before, it recognizes as well that the

1 Commission has that power described in the statute.

2 Now, for context, in at least nine states
3 today, electric utilities are required to bear some
4 portion of the fuel cost risk. Rather than be
5 assured that 100 percent of all costs are passed
6 along to ratepayers, the utilities bear some
7 responsibility for failures to reduce fuel costs.
8 And under symmetrical sharing, which I think is the
9 wisest move, investor-owned utilities like Georgia
10 Power, they also share in the upside when they can
11 successfully show that they have reduced fuel costs
12 against some agreed-upon benchmark, like NYMEX
13 futures, for instance, you could use.

14 And there are three other states that are at
15 various stages of advancing similar fuel
16 risk-sharing policies. I'm hearing of at least one
17 more in the works, and maybe a 14th. But these 12,
18 at least, represent a full one-third of those
19 vertically integrated states. And that number,
20 like I said, grows each year towards this majority.

21 So in the testimony at a policy level, I
22 explained why Georgia Power's timing of their -- of
23 this FCR-27 filing is particularly unfortunate, not
24 of their own making, because of the Iran
25 hostilities and the many consequences on global

1 energy markets, including the ongoing risks in the
2 Strait of Hormuz.

3 And because the Commission is required by
4 statute to take some sort of action on this FCR-27
5 proposal, I recommend the Commission take these
6 following steps.

7 First, reject -- formally reject the FCR-27
8 proposal and require that Georgia Power submit a
9 new proposal that reflects the updated ongoing
10 realities. One is updated natural gas forecasts
11 that reflect the likelihood that exporting natural
12 gas will become more profitable for domestic
13 suppliers and addressing that risk.

14 And the second is greater clarity on the
15 already increased oil prices and oil price
16 volatility because diesel oil represents at least
17 41 percent of the cost of coal delivery.

18 I also urge the Commission to reject the
19 utility's request to increase their natural gas
20 hedging by almost \$1.9 billion more hedging
21 authority under this FCR period if -- if adopted.
22 That's more than 267 percent of the current
23 authorized hedging authority. And to restrict
24 natural gas hedging to no more than the current
25 hedging authority. Although, you've heard others

1 who think that further action should be taken to
2 reduce that power.

3 I further urge the Commission to require, as
4 a condition of approving an updated FCR-27 proposal
5 after refiling, that the utility include a
6 10 percent fuel risk sharing responsibility that
7 the Commission -- sorry, that the utility include
8 their own 10 percent fuel risk sharing
9 responsibility, which the Commission could decide
10 to -- there's plenty of reason to, but you don't
11 need to -- tie to approval of any expanded or
12 continued interim fuel rate authority at the
13 current levels.

14 And finally, while Georgia Power is revising
15 their proposal, if the Commission were to take my
16 recommendations, I would recommend that the
17 Commission adopt the reduced interim fuel rate as
18 proposed in FCR-27, because it's likely that the
19 updated FCR-27 filing will not only be more
20 accurate, but even more likely if the Commission
21 requires Georgia Power to accept 10 percent
22 responsibility of fuel risks and fuel costs, that
23 that final, ultimate FCR-27 rate will be lower than
24 the FCR-26 rate.

25 The policy landscape is pretty clear that

1 modernizing Georgia's fuel cost recovery mechanism
2 is very likely to reduce costs for ratepayers and
3 for all ratepayers. And with symmetrical sharing
4 in place, it can also increase the profitability of
5 the utility at the same time. So I am actually
6 arguing for increasing opportunity for Georgia
7 Power to make more earnings for shareholders and to
8 maybe not recycle, but to reduce the overall fuel
9 exposure.

10 And so on that optimistic note, I thank you
11 each for your service as a former elected official
12 myself, really appreciate your time, your
13 thoughtfulness, and am available for questions.

14 MS. ARIZA: Thank you, Chairman Shaw. The
15 witnesses are available for questions from the
16 Commission and cross-examination.

17 CHAIRMAN SHAW: Thank you for your service.

18 MR. KALIN: Well, thank you. It's been a
19 little while, you know. I try not to re-offend any
20 time a ballot is -- a ballot filing period is open,
21 but, you know.

22 CHAIRMAN SHAW: On page 14 of your testimony,
23 you mentioned that the -- since 2010, the
24 Commission has not ever disallowed any fuel costs
25 for recovery from ratepayers. I do recall -- I

1 haven't been through too many fuel cases, but I do
2 recall that we have, just like in this case, staff
3 has worked hard to nail down any, you know, these
4 unplanned outages to try to find ways to disallow
5 what we can legally and prudently. So I'm just
6 wondering where you got that information.

7 MR. KALIN: Yeah. Thank you, Mr. Chair, for
8 the question. On my non-line items, line 6 or 7 in
9 my testimony, for those playing the home game, but
10 you'll note that I explained that the Commission
11 has not ever disallowed proposed fuel costs for
12 imprudent conduct or illegal conduct. And the
13 total set aside voluntarily, with stipulations not
14 very clearly not calling the conduct imprudent or
15 or illegal, is just 14 and a half million dollars
16 over that 16-year period out of -- I did a rough
17 estimate from the company's 10-k SEC disclosures
18 that I've narrowed a little bit, but out of 29 to
19 \$40 billion, only 14 and a half have been
20 voluntarily disallowed through stipulation.

21 CHAIRMAN SHAW: Yeah. I did read that
22 number. Thanks for clarifying that.

23 Commissioners, any questions for this joint
24 panel?

25 COMMISSIONER PRIDEMORE: I have a few.

1 CHAIRMAN SHAW: Go ahead.

2 COMMISSIONER PRIDEMORE: Thank you. So,
3 Mr. Kalin, in your opening statement, you were very
4 bold in the statement of you believe that fuel cost
5 recovery is a moral hazard. And you mentioned the
6 enabling legislation that requires Georgia Power to
7 give 100 percent of the costs of fuel back, and you
8 recognize that that was passed by the folks across
9 the street in the legislature and not by the
10 Commission; right?

11 MR. KALIN: A couple of corrections,
12 Commissioner. The statute doesn't require
13 100 percent pass-through as was cleared -- and, you
14 know, everything the Commission does has to operate
15 within statute rules. And it's one of the things
16 I've always wanted Commissions and legislatures to
17 cooperate a little bit more to understand that
18 dialogue. But it's not fuel cost recovery that's a
19 moral hazard. It's 100 percent pass-through as
20 currently implemented, where the bill payer is --
21 the one making the economic choices has all the
22 power of decision-making and bears none of the
23 consequence. And 99.995 percent or higher
24 collection, as has been the case since 2010, as the
25 Chair's good question highlighted, is a moral

1 hazard.

2 COMMISSIONER PRIDEMORE: But recovery and
3 pass-through are the same things. They spend money
4 on the fuel and they're allowed to recover the
5 costs of that fuel; right?

6 MR. KALIN: As the Commission decides under
7 42-2-26 the statute, as the Commission decides
8 they're permitted to recover.

9 COMMISSIONER PRIDEMORE: But in the case of
10 imprudency, if they've --

11 MR. KALIN: No, no, sorry to -- I have a -- I
12 have a bad habit of interrupting. I apologize,
13 Commissioner. I'll let you finish. I apologize
14 for that.

15 COMMISSIONER PRIDEMORE: Thanks.

16 But -- so they -- it hasn't just been since
17 2010. It's been since the enabling legislation
18 said that what they spend -- what the company
19 spends on fuel, it comes to the Commission for an
20 annual fuel case. Fuel case is evaluated, and the
21 company is then allowed to recover those costs so
22 that the -- excuse me -- so that it provides
23 consistency from a resource adequacy or from a
24 resource necessity period.

25 So you mentioned that there were nine states

1 that have -- that bear a fuel cost risk, which are
2 those nine states?

3 MR. KALIN: They're listed in my testimony,
4 but let's see if I can do them from memory.
5 Hawaii. I'm just going -- I'm going west to east
6 here.

7 COMMISSIONER PRIDEMORE: Sure.

8 MR. KALIN: Hawaii, Washington, Oregon,
9 unlikely Idaho, Wyoming, Colorado, Missouri,
10 Wisconsin, Vermont. Am I at nine? I feel like I'm
11 missing one, but I can --

12 COMMISSIONER PRIDEMORE: You're at nine.

13 MR. KALIN: Okay.

14 COMMISSIONER PRIDEMORE: You're at nine.

15 Tell me some things that these states have in
16 common.

17 MR. KALIN: You know, they're diverse.
18 They're quite diverse. In fact, I would point to
19 states like Missouri that is going through research
20 to look at expanding their sharing percentage from
21 5 percent to more. Wyoming, of all states, is at
22 20 percent sharing, and Wyoming came within one
23 vote of the Commission.

24 It's actually quite worth reading the
25 January 20, 2024, order, and the Rocky Mountain

1 Power kind of consolidated -- I think it was
2 formerly a rate case, but don't hold me to that.
3 They came within one vote of returning to a
4 30 percent sharing responsibility, finding --

5 COMMISSIONER PRIDEMORE: It's not hard to do
6 on a three-person Commission.

7 MR. KALIN: That's true.

8 COMMISSIONER PRIDEMORE: It's not hard to do.

9 MR. KALIN: A good point.

10 COMMISSIONER PRIDEMORE: When I look at these
11 nine states, the one thing that is consistent to me
12 is that all of the states, with the exception of
13 three, have a renewable portfolio standard. And
14 the one that does not have a renewable portfolio
15 standard in the case of Missouri, that it is part
16 of an RTO that is heavy wind.

17 So I think that -- I think that there's maybe
18 some opportunity for you for some research in this,
19 to identify where there's consistencies across
20 these states that have this fuel cost risk
21 mechanism put in place.

22 MR. KALIN: I'll push back on that because
23 the --

24 COMMISSIONER PRIDEMORE: I can tell. You
25 were eager.

1 MR. KALIN: I'm often eager to talk about
2 policy, especially this policy, as I know you are
3 as well. You know, states like Washington and
4 Idaho and Oregon are such heavy hydro states. And
5 as a project finance guy, you know, you look at --
6 like, if you're doing a -- well, particularly a
7 solar project, even on the east side of the
8 cascades where it's actually sunny, not on the west
9 side in the rainforest, it is very hard to
10 compete -- to outcompete that very cheap power, you
11 know.

12 COMMISSIONER PRIDEMORE: They can afford
13 their renewable portfolio standard.

14 MR. KALIN: Well, in other states, you know,
15 I think Wisconsin's an interesting case, that's
16 probably a lot more like Georgia, because they're a
17 lot like my home state of Minnesota in terms of
18 historic resource mix and moderate cost of power.
19 And they're a little more agricultural, but not
20 much more.

21 And so I think that one of the things that we
22 have seen is that the types of economies, the types
23 of utilities, the types of resources really is so
24 diverse that the fuel cost recovery, the fuel cost
25 sharing, fuel risk sharing appears to be not a

1 silver bullet, but certainly a piece of the silver
2 buckshot in addressing affordability.

3 COMMISSIONER PRIDEMORE: Thank you for your
4 testimony.

5 Mr. Goggin, I wanted to ask you, you
6 mentioned in your opening statement and in your
7 testimony -- you called out Winter Storm Fern, and
8 the fact that coal and natural gas were used
9 instead of other generation resources during Winter
10 Storm Fern, and so it made me go look.

11 Winter Storm Fern took place in the United
12 States between January 27th and January 29th of
13 2026. When it came to Georgia on January 26th, the
14 sky conditions were overcast with a high of 40 and
15 a low of 20. On the 27th, the sky conditions were
16 overcast, with a high of 39, a low of 14. On
17 January 28, the sky conditions were overcast, with
18 a high of 44 and a low of 26, and on January 29,
19 the sky conditions were overcast with a high of 43
20 and 26. Do we have wind in Georgia?

21 MR. GOGGIN: Not in Georgia, but you do
22 import from SPP.

23 COMMISSIONER PRIDEMORE: Less than 5 percent
24 of the state of Oklahoma due to the ITC. You got
25 it. But of that, with that 5 percent, is being the

1 number eight currently deployed solar state in the
2 country going to be able to fuel our state and
3 power our state during those four days of rain, ice
4 and overcast conditions, extreme cold?

5 MR. GOGGIN: Nobody's proposing that any
6 single resource should power under all conditions,
7 and that's why you need a diverse mix. And, you
8 know, the wind did perform extremely well in SPP,
9 MISO, and PJM on -- during most of Winter Storm
10 Fern. Certainly during the peak demand periods
11 wind was performing extremely well in those areas.

12 So additional imports of wind, additional
13 solar, additional batteries work well with existing
14 resources to build a reliable and cost-effective
15 portfolio.

16 COMMISSIONER PRIDEMORE: This Commission has
17 put forward a robust battery schedule for Georgia
18 Power to be able to enact, but we have baseload
19 power -- I'm an old fashioned girl, and I call it
20 what it is -- of coal and natural gas. Coal and
21 natural gas was used during the extreme weather of
22 Winter Storm Fern to be able to have us -- have the
23 lights on and our heat going during that time.

24 It's just not simply an apples-to-oranges
25 comparison in this instance, but I'm certain that

1 in the future you'll bring us some other instances
2 where the comparisons might be more similar.

3 MR. GOGGIN: Well, I mean, again, it's a
4 portfolio of resources and additional transmission
5 enabled wind can certainly fit in a lot of that.
6 It was performed extremely well during that event,
7 and all of the extreme winter event we've seen over
8 the last 15 years. Wind has been a key part of
9 keeping the lights on in many parts of the country,
10 and with expanded transmission, we can have more
11 regions benefit from that.

12 COMMISSIONER PRIDEMORE: Well, I'll -- I
13 won't bore you with the eight years I've served on
14 this Commission and the amount of work that's been
15 done to look at the possibility of wind in Georgia
16 and recognizing the limitations of topography and
17 things that we have that just doesn't make it as
18 viable as it does in the middle states of the
19 country. But I know that we are powered primarily
20 when the sky conditions are overcast, with a high
21 of 39 and a low of 14, we're powered by that
22 baseload power of coal and natural gas.

23 So thank you.

24 CHAIRMAN SHAW: Commissioner?

25 COMMISSIONER HUBBARD: Yeah, a couple of

1 questions. Let me start with you, Mr. Kalin. You
2 did mention those nine states with three others
3 that or maybe four that are falling behind. And
4 then on page 18, there was mention of the dramatic
5 benefits for reliability.

6 Could you maybe point to one or two standouts
7 from that list of states, or maybe some best
8 practices, just anything to kind of anchor on for
9 that dramatic benefit of reliability and some of
10 the other benefits that were mentioned, that you're
11 seeing from the fuel cost sharing mechanism in
12 those states?

13 MR. KALIN: One of the things that I think
14 happens in those nine states, and we've also
15 seen -- I cut my teeth initially on -- I've long
16 time been an energy conservation, energy
17 efficiency, demand side management advocate.

18 And when I was in the legislature was
19 approached by our investor-owned utility equivalent
20 to Georgia Power, XL Energy, and we worked through
21 an incentive mechanism. And we had had a
22 requirement, not unlike sort of FCR equivalent for
23 efficiency of, you know, spend this, check the box,
24 comply. You'll be good.

25 And the utility said, you know, I think we're

1 thinking about this all wrong. If we can get on
2 the same side of the table -- and, yes, you can
3 keep -- keep the existing requirements to make sure
4 we're hitting them, but what if you gave us a small
5 incentive to blow past that energy efficiency, you
6 know, resource standard effectively; right?

7 And so we agreed, you know, long story of
8 many, many conversations. We agreed, and the
9 second that the day that the Commission approved
10 this capped \$40 million incentive, the question in
11 the CEO's -- literally in the CEO's office, as I
12 understand, went from what little do we need to
13 spend to comply, to how fast can we maximize our
14 savings. And that's why -- to pick up on
15 Ms. Pryor's good -- an interesting question of
16 Mr Lin, you know, it's not really about recycling.
17 It's about reducing; right? I don't think we're on
18 the same side of the table sufficiently to get
19 Georgia Power looking much more aggressively.

20 That's why I'm a big fan of the symmetrical
21 sharing to share the upside, because I think that
22 we know that tipping to cost effectiveness and
23 energy -- and demand-side management, for instance,
24 there is another 100 million and another
25 100 million and another 100 million tranche of

1 savings that the utility can help harvest, if
2 they're on that same side of the table, and they
3 get paid earnings opportunities. That's really
4 significant.

5 And then I think the same is true in terms of
6 dispatching and adding more no fuel resources,
7 whether it's out-of-state wind or in-state solar
8 and batteries that just don't have that fuel mix.
9 It changes the conversation. And, you know, in
10 Mr. Hewitson's office, for instance, about what
11 really does make sense, and how much more can we
12 capture.

13 We're just leaving all sorts of value on the
14 table that's just getting burned up the smokestack
15 effectively that I think we could do -- that
16 Georgia could experience savings.

17 There was just an analysis done of -- in the
18 state of North Carolina. I think I included it in
19 my testimony, that if the -- if fuel cost sharing,
20 fuel cost sharing had been in place in that state
21 in the last five years, that ratepayers would have
22 benefited \$89 million through more cost-effective
23 dispatch of non-fuel resources and other -- in
24 energy efficiency. And the utility would have
25 netted another \$10 million of earnings over those

1 five years. And, you know, that's a first-pass
2 calculation that, I think, RMI has done, but I
3 think that it may be something the Commission wants
4 to look at here about what that analysis might look
5 like.

6 COMMISSIONER HUBBARD: So it's your position
7 that with a symmetrical fuel cost sharing mechanism
8 that there could be a win-win, both for the utility
9 in terms of earnings and revenues, and all of that,
10 but also on the side of the ratepayers as well? It
11 could be a win-win in that sense?

12 MR. KALIN: Yeah. And I think we're -- I
13 think we're seeing that very much in those nine
14 states. And even in states where it's not yet been
15 adopted, there's been pretty clear interest,
16 particularly from staff, that I think that's -- you
17 know, a few staff, including here, as I see, are
18 really the ones who understand the details with
19 trade secret access and pouring over all the
20 information that, you know, just today alone is
21 good enough witness.

22 And it's staff that are continuing to
23 supplement the record showing -- for instance, in
24 Arizona, where it kind of got swept out -- they had
25 a 10 percent share in responsibility -- was swept

1 out in a bunch of unrelated policy moves, and staff
2 has said we need to know more again about what this
3 10 percent savings would look like here, because it
4 does appear to be that true win-win that does make
5 sense.

6 COMMISSIONER HUBBARD: One more question for
7 you. On page 19, you mentioned -- well, you cited,
8 actually, the company's testimony that any
9 evaluation of the economic impact of FCR-27 must be
10 considered within the context of their next base
11 rate case. Is there a linkage between this FCR and
12 that next base rate case? Because I've always
13 considered these dockets to be one-offs and always
14 separate from each other. But as -- and I also saw
15 that the storm damage recovery was filed
16 concurrently with this. So are there linkages
17 among dockets here that we're missing out on, that
18 we should be paying attention to?

19 MR. KALIN: What I think has been useful for
20 me to understand is the rigor of a -- of a rate
21 case and an integrated resource plan is really
22 forward-looking. Even the base, even the -- the
23 rate cases, how much revenue do we think you're
24 going to need to operate? I'm a simpleton when it
25 comes to ratemaking compared to like Mr. Goggin and

1 many of you-all here.

2 But we don't get an opportunity to bring the
3 rigor outside of these fuel cost recovery dockets
4 here, to bring the rigor to say, do we -- were we
5 right in our assumptions. And I think that
6 historically, while it is a challenge for staff, if
7 we were to -- if y'all were to say, let's
8 consolidate these all into -- and I see,
9 Mr. Chair -- the nightmare of asking staff to
10 say -- to look at an IRP, a rate case, and fuel at
11 the same time, except why not; right?

12 I think because they're -- we're really
13 saying if we set the price of five bucks for gas in
14 an IRP, and now we have been volatile for years and
15 we're now at nine, and we've just been up and down
16 and up and down, or whatever that was, did we get
17 it right? Should we reevaluate? Are there
18 additional ways that we could partner with the
19 utility? This shouldn't be a fight. It really
20 should be a partnership about having the most
21 efficient, diverse set of supply and the best way
22 to meet new load and existing load.

23 COMMISSIONER HUBBARD: Okay. No more
24 questions, but just a comment, and thank you for
25 bringing up the history of 1970s, the '73, '79 oil

1 crises that triggered this reexamination of fuel
2 cost sharing mechanisms and whether or not it
3 should be included in base rates or should be
4 passed down.

5 And I mean, I think just in the present
6 context with the war in Iran, circumstances change
7 and we should reexamine these things from time to
8 time, and I don't think we've done that here at
9 least since 2010. So just a comment there.

10 Mr. Goggin, the 152 million in uneconomic
11 cold dispatch, that is exclusive of transmission
12 constraints you mentioned. And also doesn't take
13 into -- or does take into account, but excludes
14 must-run requirements for these coal units that
15 were economically dispatched in your view.

16 Are there any other constraints that we're
17 playing out there, or is this really just there
18 were other options and from your analysis, the
19 company didn't choose to dispatch, say, lower cost
20 resources, including gas, solar, or whatever may
21 have been available, just wasn't dispatched.

22 MR. GOGGIN: Yes. First, you're absolutely
23 correct that that \$152 million excludes
24 transmission congestion and excludes the must-runs.
25 Those are separate and they're tabulated

1 separately. In my direct testimony, and the trade
2 secret, you can see the numbers associated with
3 that.

4 So the -- you know, any arguments that, oh,
5 we needed to commit these coal units because of
6 transmission constraints, we need to maintain
7 reliability on this part of the system, that was
8 excluded. We have accounted for that. That is not
9 reflected at all in the \$152 million. That's a
10 separate number that we've separated out, and we
11 did not call for disallowance of that because we
12 did not have enough information to assess the
13 prudence of those decisions. We just didn't have
14 the information to the company's dispatch decisions
15 and the transmission model to understand, did they
16 really have to dispatch because of those
17 conditions?

18 So we just conservatively said, okay, we're
19 going to take you at your word on those costs
20 related to transmission and must-run. We're not
21 going to -- you know, those were presumably
22 prudent. We're not going to call for disallowance
23 of those, everything. We are calling for
24 disallowance of this for other reasons.

25 And so the question is, then, what is this

1 other reason? Identified biases in the inputs into
2 their commitment process, and those numbers are
3 called out in my testimony. And those biases are
4 basically overstating need in the day-ahead time
5 frame, and that is causing the -- one of the
6 factors that is probably causing the overcommitment
7 of coal generation.

8 The other big factor that seems to be going
9 on here is -- and, you know, staff highlighted this
10 as well -- is that gas was cheap throughout a lot
11 of this period, and so coal piles built up. And
12 the minimum delivery requirements in the coal
13 contracts basically start hitting. There are
14 penalties that come into effect if you are not
15 taking as much coal as you contracted for. And
16 basically you're in that situation where if you
17 can't put any more coal in the pile, either pay the
18 penalty or you burn it.

19 And so burning it is -- you know, basically
20 you're uneconomically running the units. And we
21 know that the company disclosed that, you know, it
22 is using -- in discovery it disclosed that it
23 basically is putting in a price decrement that, you
24 know, takes out that penalty cost. And so,
25 therefore, you're kind of basically like

1 subsidizing the coal. It looks cheaper than it
2 really is, because you're not accounting for that
3 penalty.

4 But we -- you know, there's also probably
5 just -- you know, it's difficult to identify this
6 because, you know, the company wasn't particularly
7 forthcoming. But putting your thumb on the scale,
8 you know, you've got this big coal pile, you want
9 to run your coal more than you were, and I think
10 that's what's going on here.

11 COMMISSIONER HUBBARD: So 152 million is a
12 pretty significant number here, and I'm just
13 curious, did the -- in discovery, was there any
14 follow-up information provided by the company that
15 would have helped to validate that 152 million or
16 disprove it? I mean, you know, any dispatch
17 information from, you know, sort of Mr. Reynolds,
18 Witness Reynolds, really dug down into a forensic
19 analysis. And I'm just curious if any additional
20 information was provided to prove or disprove what
21 you were claiming.

22 MR. GOGGIN: Yeah, I thought staff's
23 testimony a few panels ago, you know, the written
24 testimony, as well as their appearance here today,
25 did a good job of explaining that, you know, they

1 were really trying to get into that, understand
2 this uneconomic dispatch. And just the company was
3 not forthcoming enough in, you know, how it was
4 making dispatch decisions, and basically say it
5 doesn't have the records to provide them.

6 And so that's why we did our analysis. It's
7 basically we reconstructed based on all of the
8 inputs that we got from the company, on, you know,
9 the hourly cost of these coal units. The lambda,
10 the day-ahead lambda that the company has,
11 basically, it's a pretty simple -- the idea is very
12 simple.

13 In the day-ahead time frame when the company
14 decided to run this coal unit, was that coal unit
15 more expensive or less expensive than what the
16 company thought the cost of producing electricity
17 across the system was going to be the next day.
18 And it's pretty simple that, you know, economics
19 says, if it's cheaper, run it. If it's more
20 expensive, don't run it. And so then we found
21 those periods where the coal unit was more
22 expensive and they ran it anyway, and that's where
23 the \$152 million came from. With a lot of other --
24 you know, we accounted for the startup costs,
25 shutdown costs, all their operating parameters, all

1 of that. That's all factored in as well.

2 COMMISSIONER HUBBARD: So this was subject to
3 security constraints for this economic dispatch, in
4 other words?

5 MR. GOGGIN: Absolutely. We, through
6 discovery, got the operating constraints of the
7 units, and those were applied in the analysis.

8 COMMISSIONER HUBBARD: Okay. Thank you.

9 CHAIRMAN SHAW: Any other questions?

10 VICE-CHAIRMAN MCDONALD: I might make a
11 disclosure. I voted on the fuel case in the late
12 '70s, when I was across the street.

13 MR. KALIN: Could I add, Mr. Chair, if it's
14 all right?

15 CHAIRMAN SHAW: Yes.

16 MR. KALIN: A comment to the former
17 legislator. I learned a great deal in the last few
18 weeks reviewing what the mid-'70s dialogue was that
19 leading -- that led up to that statute that I found
20 fascinating. And you may too, as well. Three days
21 of hearings in Congress on this very dry subject.

22 VICE-CHAIRMAN MCDONALD: We've gone through
23 some tough economic times right in those times too.

24 MR. KALIN: I won't tell you how young or old
25 I was when you voted on that.

1 VICE-CHAIRMAN MCDONALD: You were still in
2 high school.

3 CHAIRMAN SHAW: No, he wasn't there.

4 MR. KALIN: I was not in the formative under
5 clothing, at least.

6 COMMISSIONER JOHNSON: I wasn't born until
7 1973, so don't feel bad.

8 CHAIRMAN SHAW: Georgia Public Service
9 Commission.

10 MR. COLLADO: Just a brief, brief question
11 for Witness Kalin.

12 CROSS-EXAMINATION

13 BY MR. COLLADO:

14 Q. You mentioned -- or we discussed the
15 10 percent utility fuel risk share mechanism that you
16 recommended.

17 VICE-CHAIRMAN MCDONALD: Speak up a little
18 bit.

19 MR. COLLADO: Yes, sir. Yes, sir.

20 BY MR. COLLADO:

21 Q. Regarding the 10 percent utility fuel risk
22 share mechanism, would risk sharing, as proposed by you,
23 incentivize over forecasting fuel costs on the part of
24 Georgia Power?

25 A. (Witness Kalin) You've recognized the -- one

1 of the really key elements outlined in that handbook.
2 That's -- I think it's Exhibit 2 to my testimony -- that
3 forecasting is so important to set the base where we're
4 doing the upside or downside. And that's why I think it's
5 really useful to the discussion had with the Commission to
6 think about what's the proper benchmark to use, and to
7 also, then, align all those benchmarks from rate cases to
8 integrated resource plans, to plant specific assumptions,
9 to fuel forecasts.

10 And what we've seen is that that's -- that
11 tends to be not as difficult as one might expect it to be
12 in the precedent cases that -- or states that we've seen.

13 Q. And as part of that recommendation, you
14 recommended applying it to this proceeding, FCR-27. How
15 would the fuel risk sharing mechanism integrate with the
16 staff's detailed prudence adjustments, specifically, the
17 \$10 million outage, really, the disallowance that staff
18 has part of their statement -- or part of their position.

19 A. (Witness Kalin) I think the fuel sharing
20 should be forward looking and should never abandon that
21 prudence review to begin with. And so part of the
22 analysis of -- you go through the same analysis of
23 prudence, and I think the same standards, very little
24 would need to be changed in the rules. And nothing in the
25 statute that I could see that would allow for fuel cost

1 recovery -- or sorry, for fuel risk sharing, combined with
2 prudence that looks backward. So I think that they're
3 simpatico.

4 Q. So it wouldn't be like 10 percent after
5 disallowances or -- or it would be like -- or it would be
6 at 10 percent after disallowances. It wouldn't be like
7 disallowances are kind of wrapped into the 10 percent;
8 correct?

9 A. (Witness Kalin) So, yeah, a lot of the --
10 what I didn't want to do is to have an entire docket on
11 fuel risk sharing sort of sparked, although I think that
12 would be -- could be a way to proceed. And as you may
13 recall with precision that the recommendation of the
14 Commission is actually not to initiate it yourself, but to
15 require the company to make a proposal for risk sharing,
16 in part, because we want the company to be fully embracing
17 the -- and to understand the mechanisms.

18 So it's a real partnership with the
19 Commission and the public. But I think that a lot of the
20 issues that you're describing sort of is it -- you start
21 with assuming that 90 percent gets collected and passed
22 through, and you're just doing 10 percent. Is it some
23 states have a -- in my FCR-26 testimony, that's available
24 as an exhibit to Mr. Lin's testimony, you see a dead band
25 where there's no sharing involved. It's only the changes,

1 those deltas.

2 And so there's a bunch of factors that need
3 to be evaluated for what's the most cost-effective way.
4 And our goal is to not soak the utility in any way. But
5 right now we're soaking ratepayers because of this moral
6 hazard that's 100 percent set. So you're identifying a
7 lot of the issues that need to be addressed. And I think
8 that it's best to ask the utility to initiate that
9 conversation from a workability perspective.

10 I doubt that my client here would say rubber
11 stamp the utility's proposal. I think we all should be
12 looking with rigor, including the Commission and staff.
13 But again, we want this to be workable for a utility, and
14 that's where those nine states are showing success.

15 Q. And last question, would introducing the risk
16 sharing in FCR-27 require changes to the Commission's MFR
17 processes, and, if so, which elements would you think need
18 to be changed?

19 A. (Witness Kalin) I'm not intimately familiar
20 enough to know the details, but my sense is not that much,
21 if any. But I think that you're working from almost the
22 exact same backbone of process. Just having a greater
23 scrutiny over a delta. And then how much was the utility
24 responsible for helping deliver some of that savings
25 ultimately.

1 MR. COLLADO: Okay. No further questions.

2 Thank you.

3 CHAIRMAN SHAW: Georgia Association of
4 Manufacturers.

5 MR. JONES: No questions.

6 CHAIRMAN SHAW: Georgia Interfaith Power &
7 Light and Southface.

8 MS. WHITFIELD: No questions.

9 CHAIRMAN SHAW: MARTA.

10 MR. BAKER: No questions, Mr. Chairman.

11 CHAIRMAN SHAW: Resource Supply Management.

12 (No response.)

13 Georgia Power.

14 MR. HEWITSON: You sound so excited.

15 CHAIRMAN SHAW: I'm ready to go home. Well,
16 I can't go home. That's four hours away, but you
17 know what I mean.

18 MR. HEWITSON: Understood.

19 CROSS-EXAMINATION

20 BY MR. HEWITSON:

21 Q. Gentlemen, how are you this evening?

22 A. (Witness Goggin) Good. How are you?

23 Q. Good. Good to see you again.

24 For the record, Steve Hewitson on behalf of
25 the Georgia Power Company. I'm going to start with you,

1 Mr. Kalin, only because your outline came first in my
2 notebook, so I might as well not confuse myself and move
3 things around.

4 Is it fair to say that you are advocating for
5 a policy change regarding how fuel costs should be
6 recovered for Georgia Power?

7 A. (Witness Kalin) I'm asking -- I think that
8 the -- it's fair to say that the Commission would be
9 changing the policy under the statute for how it
10 implements the statute.

11 Q. Your testimony does not identify any specific
12 costs that you contend are imprudent or should be
13 disallowed; right?

14 A. (Witness Kalin) That's not the scope of my
15 testimony.

16 Q. Okay. Regarding your fuel cost sharing
17 proposal, you recommend Georgia Power be responsible for
18 10 percent of the total cost of all fuel expense risk;
19 right?

20 A. (Witness Kalin) Yes.

21 Q. Okay. You are proposing this -- you're not
22 proposing this as a one-time pilot? You're proposing that
23 it's a change going forward, a policy change to be applied
24 in all future FCR tariffs; right?

25 A. (Witness Kalin) I'm proposing that the

1 Commission require the utility to make a proposal for
2 sharing, and the Commission -- it's up to the Commission
3 to decide whether that 10 percent is the good starting
4 point to urge you or another starting point. But that's
5 the -- that's just to be precise about the recommendation.

6 Q. Okay. And how fuel cost sharing works, under
7 the proposal that I read in your testimony because there
8 can be different ways of doing it; right? How it would
9 work under yours is the company first sets a fuel cost
10 budget, which could be annually, tri-annually, whatever
11 the time period is to be set; right?

12 A. (Witness Kalin) (Nods head.)

13 Q. You've got to answer for her. She can't get
14 a head nod.

15 A. (Witness Kalin) I didn't know if that was
16 a question or a comma, conversational comma.

17 Q. Comma, right, question mark?

18 A. (Witness Kalin) Okay. It can be done on a
19 budget basis or it can be done on a volumetric basis. I
20 think the budget is probably the proper way to go, but
21 that's -- that's to be deliberated.

22 Q. And if actual fuel costs are above budget,
23 the company recovers 90 percent of the additional costs
24 and is responsible for 10 percent of the over-budget
25 amount; right?

1 A. (Witness Kalin) That's not written in stone.
2 It can be that the Commission can require that the utility
3 make a proposal where you're responsible only for changes
4 from certain -- like I said, there's some dead bands where
5 no responsibility exists. There's some models where
6 it's -- you're only responsible for 10 percent of the
7 delta. So that would be 1 percent; right? It's
8 10 percent of 10 percent; 1 percent of the total budget.
9 There's a number of different iterations. And so I can
10 imagine where you're -- where you're heading. I just want
11 to be clear that there's a lot of variation and a lot of
12 good thought that needs to go into getting this right
13 enough to proceed.

14 And I would just argue that every FCR is a
15 pilot because you don't -- because there's so much
16 variability across all these pricing and that we're -- the
17 company is always under-recovered or over-recovered at
18 some point coming in for a fuel cost. So it's all kind of
19 a pilot of some sort about is this working.

20 Q. And regardless of how it works, it is,
21 without a doubt, a risk sharing mechanism, right, where
22 the company takes on additional risk for fuel costs; is
23 that right?

24 A. A risk and reward sharing, right.

25 Q. Putting additional risk on the company could

1 change the way rating agencies view the company; right?

2 A. (Witness Kalin) I have not seen rating
3 agencies down rate any of the nine utilities. Not done a
4 rigorous review, but certainly that has not come up as a
5 concern in front of the commissions that I've seen.

6 Q. Okay. But you didn't provide any of that
7 information in your testimony; right?

8 A. (Witness Kalin) That's, I think, a good
9 conversation to be had with a proposal coming forward.
10 And I think a well-crafted proposal with good rules and
11 guidance from the Commission, I think, could be part of
12 that conversation.

13 Q. Okay. Now, you mentioned an upside that the
14 company may have, right, that upside when fuel costs are
15 lower than forecast would be earnings to Georgia Power;
16 right?

17 A. (Witness Kalin) Correct. Or at least -- I'm
18 going to accept the assumption -- presumption of your
19 question that we're doing a strict budget model, and --
20 because it could be -- the reward could be based on any
21 number of the factors that we just described in a couple
22 of questions and answers ago.

23 Q. But if it's a straight budget model, it's
24 earnings to the company; right?

25 A. (Witness Kalin) Correct.

1 Q. Okay. And would those earnings be over and
2 above the return authorized in base rate?

3 A. (Witness Kalin) This is a -- this is a policy
4 question for the Commission about whether to integrate,
5 and this is why having this conversation, at least with
6 consciousness of the rate case and of earnings is really,
7 really important, because we don't want to runaway train
8 for y'all, but we don't want a runaway train that's
9 dumping all this risk and cost on ratepayers, which is
10 where we are now.

11 Q. But under the current structure, Georgia
12 Power does not earn a return on fuel; right?

13 A. (Witness Kalin) I don't think that that's
14 true. That's a -- that's a statement that's often made,
15 and I think that it's not precise, because I think that,
16 first of all, the parent, I believe, Georgia Power has
17 fuel contracts -- I think we had a discussion earlier
18 today with other witnesses -- for other Southern Company
19 suppliers.

20 Q. That's not Georgia Power. So let's stick to
21 Georgia Power. Does Georgia Power --

22 A. (Witness Kalin) I think it's responsible to
23 to look at it holistically. And the second is that this
24 is why I think rate cases and integrated resource plans
25 are so critical to be reviewed with fuel cases. Because

1 what we see, and I don't know enough yet to say
2 definitively no or yes here, but what we see is an
3 overreliance on fossil fuel plants or fuel plants, as
4 opposed to no fuel plants, that leads to overbuilding in
5 some cases, in some states, of plants, because you start
6 with assumptions of cost effect- -- fuel rates that are
7 cost effective. And later in fuel recovery dockets, you
8 discover that those fuel costs are much higher and that
9 those initial plants would not have been authorized or
10 economic. And I think actually this dovetails with
11 Mr. Goggin's testimony kind of writ large as well. So I
12 just want to give some pushback, Mr. Hewitson, on that
13 point.

14 Q. Well, I understand that, but did you identify
15 any return that Georgia Power earns on its fuel cost
16 balance?

17 A. (Witness Kalin) I have not done an exhaustive
18 investigation either way. I can't say that y'all don't
19 earn earnings, and I can't say that y'all do -- have made
20 earnings or additional basis points as a result. I don't
21 know enough yet.

22 Q. So you don't know because you haven't looked
23 into it?

24 A. (Witness Kalin) I think that that would
25 require a level of rigorous analysis that the Commission

1 should undertake, but it'd be far better to get on the
2 same side and to see what we do going forward.

3 Q. So you have not looked at it?

4 A. I mean, I'm not going to repeat the -- I
5 already answered the question.

6 Q. No. You said that's something the Commission
7 should looked at -- should look at it.

8 A. (Witness Kalin) No, I did answer it,
9 Mr. Hewitson, I did.

10 Q. Okay. Just to make sure I'm clear, maybe I
11 missed it, you have not looked into whether the Georgia
12 Power earns a return on its fuel cost balance; right?

13 A. I can't say exclusively -- I can't say
14 definitively that you do not earn a return on fuel.

15 Q. Mr. Kalin, that's not my question. My
16 question is, did you look into it?

17 A. I just answered the question.

18 Q. Okay. The benchmark for fuel-sharing
19 mechanism is the budget that a utility sets for fuel
20 costs; right?

21 A. (Witness Kalin) It can be, but it need not
22 be. There are other models other than the strict budget
23 model.

24 Q. Okay. In what you propose related to the IFR
25 mechanism in this proceeding, I'm going by that, in your

1 recommendations, if the Commission were to adopt the IFR
2 proceeding, you said it should be conditional --

3 A. (Witness Kalin) Do you mean a fuel risk
4 sharing proceeding? You're saying IFR.

5 Q. IFR, IFR mechanism, if they approve the
6 increase in the fuel -- the IFR mechanism.

7 A. (Witness Kalin) I'm suggesting that they
8 could elect to tie them together. Without doing so, they
9 should not.

10 Q. Okay. Well, that -- and when I talk about
11 percentages, that's the percentage you gave me in your
12 testimony, so that's what I'm going on.

13 A. Wait. Can you repeat that? Sorry.

14 Q. When I was talking about percentages or
15 setting a benchmark, that was the proposal that I thought
16 you were putting forward to the Commission. Is that not
17 your proposal to the Commission?

18 A. (Witness Kalin) No, I don't think I made a
19 specific proposal. Again, I just reiterate that I think
20 that it's best that the Commission require the utility to
21 bring forward a workable fuel risk sharing proposal that
22 includes symmetrical, so it can make more money for y'all.

23 Q. Okay.

24 A. (Witness Kalin) And it could be tied to the
25 interim fuel rate but need not be.

1 Q. Okay. And one of the steps in a fuel cost
2 sharing mechanism is a benchmark by which to judge whether
3 the company was over or under on its actual fuel; right?

4 A. (Witness Kalin) Yeah. The setting of that
5 benchmark is really important, if you're going to give an
6 incentive or a penalty for, you know -- it's a key
7 performance indicator; right?

8 Q. Right. And Mr. Collado asked you, could it
9 be -- could there be a contra-incentive to the company to
10 set a fuel budget that's higher than necessary; right?

11 A. (Witness Kalin) So the current process
12 includes that incentive now, when you include wanting to
13 prove cost-effective capital improvements at plants and
14 then keep collecting that fuel revenue. And so that's
15 part of what we see is this lack of alignment between the
16 fuel costs at each step. So you're correct that
17 setting -- that setting that benchmark is really, really
18 important.

19 Q. Customers only pay the actual fuel costs that
20 they incur, right, that the company incurs?

21 A. (Witness Kalin) I'm not sure I understand the
22 follow-up link there.

23 Q. Okay. Customers only end up paying the
24 actual fuel costs that the company incurs; right? That's
25 what Commissioner Pridemore was asking you about a

1 pass-through.

2 A. (Witness Kalin) Everything that's within the
3 FCR tariff, customers pay, correct.

4 Q. Okay. And fuel budgets are --

5 A. (Witness Kalin) And, Mr. Hewitson, if a
6 plant were certified as cost-effective and granted a
7 certificate of public necessity, certificate of need, at,
8 let's say, \$2, and an assumption of \$2 gas, and you're at
9 \$8 gas, would that plant still -- and the forecast been
10 more accurate at the point of the plant proposal, plant
11 application, would that plant have been deemed cost
12 effective? Probably not -- right? -- so that's the --
13 that's what the current scenario is. Maybe I should say.
14 Let me -- that's what the current scenario may be in
15 Georgia and is in other states. And that's a real
16 problem.

17 Q. And that's a recertification issue, and an
18 IRP planning issue, as well as a fuel issue; right?

19 A. It is an issue for rate setting. It's an
20 issue for fuel tariffs. It's an -- it's an issue -- I
21 mean, you could, I suppose, be open. I don't think
22 that -- I think your rating agencies would really not like
23 this, but you could be open to say, let's go reevaluate
24 the cost effectiveness of every plant that's been
25 certified. That's not -- that's not what we're proposing.

1 And so that's why going forward, again, we think bearing a
2 little bit of risk makes a whole lot of sense here in
3 exchange for sharing the upside, with that benchmark being
4 clearly established through good proceedings.

5 Q. Okay. Now, you've gone far afield of the
6 original question, which was, customers only pay for the
7 actual fuel, in an FCR proceeding, there's a historical
8 period that then sets future budgets. There's a future
9 budget set on a projection, and then that is trued up at
10 the end of the FCR proceeding, at the end of the FCR
11 period, and customers pay the actual fuel cost, not based
12 on the budget that was set; right?

13 A. (Witness Kalin) Yes and no.

14 Q. Okay. Why no?

15 A. (Witness Kalin) I think the testimony that
16 we've heard all day details why that's an
17 oversimplification of what the reality is, because there's
18 got to be -- because you have prudence reviews, you have
19 your stipulations where you voluntarily remove. There are
20 items that are currently included in FCR that are not
21 fuel. There are a number of items. So that's why I'm
22 pushing back on your simplification, and the evaluation of
23 the cost effectiveness of the plants in the first place is
24 the challenge. And I would argue that -- and I think the
25 evidence supports this statement that those -- that good

1 fuel sharing ends up with better analysis of proposed
2 plants as well, because you have a more aligned assumption
3 on pricing.

4 Q. Yeah. But you've gone to other aspects. The
5 question -- once the fuel budget is set, that's what rates
6 are set on. And after the end of the fuel cost recovery
7 period, customers are trued up and they have only paid --
8 they're only paying what was actually included -- or
9 actual fuel costs, as fuel costs have been defined by this
10 Commission; right?

11 A. (Witness Kalin) I think you're describing the
12 existing fuel cost recovery regime.

13 Q. Thank you.

14 A. (Witness Kalin) And what I'm also making,
15 trying to make clear is that there have been repercussions
16 for ratepayers to the tune of billions and billions of
17 dollars, a potentially not cost-effective plants and
18 non-cost-effective fuel expenditures we want to avoid for
19 the future.

20 So going forward, rather than over-litigating
21 the past, accepting that the Commission is where it is and
22 the findings that we -- that the Chair wisely asked about
23 that 14.5 million that was voluntarily removed in the last
24 15 years, we want to go forward, and so figuring out what
25 does it look like going forward on an appropriate

1 mechanism.

2 Q. Setting fuel budgets is inherently difficult;
3 right?

4 A. (Witness Kalin) Fuel forecasting and price
5 volatility is inherently difficult, and that's why the
6 current regime is a problem for ratepayers in Georgia.

7 Q. Right. Natural gas prices can be impacted by
8 lots of things outside of Georgia Power's control; right?

9 A. (Witness Kalin) There are a lot of things
10 that Georgia Power does that are also in global
11 environments. And you find ways to manage the company
12 just like every other utility. It's not done in a vacuum
13 for sure.

14 Q. There are other things like technological
15 developments that could, like fracking, that if the
16 company had set a budget or did set a budget before
17 fracking really took off, the budget could be much higher
18 than actual costs, and the company ends up with a windfall
19 simply because of technological advancement during the
20 period; right?

21 A. (Witness Kalin) I would imagine that in your
22 wisdom, you would counsel your client to not have a
23 runaway train, but have some sort of cap on what could be
24 earned from those earnings. I don't think the Commission
25 would authorize an open-ended blank check either.

1 Q. You would prefer there to be signals -- or
2 you tell me, would you prefer that there be greater
3 signals from fuel price, or from the overall cost to
4 customers of operating the system?

5 A. (Witness Kalin) I don't think we have to make
6 that choice.

7 Q. You mentioned several times in your testimony
8 and in discussion with the Commissioners that nine states
9 have adopted some sort of fuel risk sharing; right?

10 A. Correct.

11 Q. Does that means 41 states have not?

12 A. (Witness Kalin) No. There are 14 states that
13 are in -- I suppose, the District of Columbia, as well --
14 there are 14 states out of the 51 that are not vertically
15 integrated. And interestingly, it's -- you could read
16 their environments, their regulatory regimes as having
17 100 percent responsibility of the utility or something
18 different.

19 So it's really -- I don't count those because
20 I don't think it's fair to come here and say, you know, 9
21 plus 3 plus 14 is 26. It's a majority. That's not quite
22 accurate either, because we want to compare Georgia to
23 other vertically integrated states.

24 Q. No, I was just going through your math to
25 make sure you're right.

1 COMMISSIONER PRIDEMORE: The 14 states that
2 have no choice but to buy through an IPP, that is a
3 complete apples-and-oranges comparison.

4 MR. KALIN: And that's my point,
5 Commissioner, 100 percent.

6 COMMISSIONER PRIDEMORE: That's not --
7 there's a -- there's a greater delineation between
8 those states that have a renewable portfolio
9 standard or a future gas docket that's either been
10 passed or that is in process right now, where the
11 goal is to either eliminate coal, which most of
12 those states have already done, or never had it to
13 begin with, in a couple of examples, and then to
14 eliminate natural gas. So they're basically --
15 they're basically pricing gas out of the resource
16 mix.

17 MR. KALIN: Commissioner, I was really
18 excited that we were in agreement, and then the
19 second part there, now we return to our
20 disagreement posture. But I appreciate you very
21 much. Yeah. We -- let's look at vertically
22 integrated states; right.

23 BY MR. HEWITSON:

24 Q. One of the nine states you identify, Montana,
25 has actually suspended its program after seven years to

1 reevaluate whether it's doing what they expected it to do;
2 right?

3 A. So we see a little flow back and forth. And,
4 you know, Montana's neighbor, Wyoming, like I said, went
5 through a rigorous review. It's actually, I think,
6 footnote 24, maybe is the citation of the document. Yes,
7 it's footnote 24. And, you know, in Arizona, which I
8 believe I've explained a good bit as well, you know, they
9 had removed it. And then now staff is urging looking at
10 it again. I expect there to be, as there should be,
11 rigorous, reviews across the board of is this effective.

12 Q. Okay. Let's turn to the moral hazard
13 argument. When you say the current framework creates a
14 moral hazard, you're not pointing to a specific instance
15 where the company has acted imprudently or illegally in
16 this FCR period; right?

17 A. (Witness Kalin) This is a description of
18 anytime you have a decision maker that doesn't bear the
19 consequences of that decision, and particularly
20 financially, economists classify that as a moral hazard.

21 Q. Right. It's a generic theory. Forgive
22 generic. It's a broad theory --

23 A. (Witness Kalin) Yes.

24 Q. -- that states that if the individual taking
25 action is insulated from risk, they will act more risky.

1 A. (Witness Kalin) I think that's a -- that's
2 a --

3 Q. Super simplified version.

4 A. (Witness Kalin) Yeah.

5 Q. Your testimony doesn't discuss all the
6 ways --

7 COMMISSIONER PRIDEMORE: By Paul Krugman.

8 MR. KALIN: Oh, I don't think it's a Paul
9 Krugman argument at all. I think it's a classic --
10 I think it's --

11 COMMISSIONER PRIDEMORE: He's made it many
12 times.

13 MR. KALIN: Yeah. But I think it's -- I
14 actually think it's -- don't hold me to this, but I
15 think it's a University of Chicago origin, or at
16 least an advocate. I'm not an economist. I just
17 happen to read, like, decent economists.

18 MR. HEWITSON: But I think it's from Hewitson
19 in 2026.

20 MR. KALIN: Yeah. There you go.

21 MR. HEWITSON: All right.

22 MR. KALIN: Leave it to the number cruncher,
23 Mr. Goggin, might actually be able to point us in a
24 better direction, but yeah.

25 BY MR. HEWITSON:

1 Q. All right. Your testimony does not discuss
2 the ways that Georgia Power already manages its fuel
3 costs; right? That's not part of your testimony?

4 A. (Witness Kalin) That's not the scope of my
5 appearance here.

6 Q. Okay. So you didn't discuss the hundreds of
7 employees focused on maintaining efficient generating
8 units; right?

9 A. What I -- what I don't know is whether -- is
10 the extent to which -- and I'd be very curious the number
11 of full-time employees that actually purchase fuel, either
12 at Southern Company or at Georgia Power. I do know
13 another similarly situated holding company across multiple
14 states that -- whereas, reported that they had four
15 full-time employees across that multi-state environment
16 managing fuel. Whether that's just an exaggeration or the
17 reality, it reflects that the -- that utility and it is a
18 vertically integrated utility is insulated from the risks.

19 Q. But your testimony doesn't talk about it?

20 A. I did not -- that's not the scope of my
21 testimony.

22 Q. And you don't discuss how Georgia Power
23 dispatches its fleet using a production cost model that
24 determines the most efficient fleet resources to use;
25 right?

1 A. (Witness Kalin) I don't discuss it because
2 that's not the purpose of my appearance here.

3 Q. Yeah. And you don't discuss how Georgia
4 Power has added thousands of megawatts of solar and
5 batteries over the last several years; right?

6 A. What I -- what I don't know, but I know that
7 the other dockets extensively show, is how much more cost
8 effective solar and storage in particular and demand-side
9 management energy efficiency could continue to be built
10 and harvested that would be great for the company and
11 great for ratepayers.

12 Q. And you are aware of the RFP process that was
13 just completed in Georgia recently?

14 A. (Witness Kalin) I'm aware of it.

15 Q. Are you aware generally of the diverse mix of
16 resources that were procured through that RFP
17 certification?

18 A. (Witness Kalin) I'm not intimately familiar
19 with the -- with the details of that mix, but I can tell
20 you that it would probably be even more in the interest of
21 ratepayers if you were -- if you had to bear -- if your
22 client -- if the company had to bear some portion of the
23 fuel risk.

24 Q. But you're aware of the IRP statute and the
25 requirement of Georgia Power to run an RFP before

1 procuring any supply-side resources; right?

2 A. (Witness Kalin) I will take your word at it.
3 I believe so when I've reviewed the statute, but that's
4 not the emphasis of my appearance here.

5 Q. No, but it does also mean that it's not
6 100 percent Georgia Power's decision on which resources to
7 procure or build; right?

8 A. I will -- I'm not familiar enough with the
9 RFP judging process. I'm -- have advised colleagues on
10 other -- both proposals and reviews of utility scale RFP
11 procurement. But I think that I'll go back to my original
12 statement that the scoping of the -- of future RFPs would
13 be different, and more in the interest of ratepayers and
14 reliability, if you were not fully insulated, if the
15 company was not fully insulated from fuel costs for the
16 life of those plants.

17 Q. And all generation resources have to be
18 approved by the Commission? That's your understanding;
19 right?

20 A. (Witness Kalin) And the Commission should
21 more closely -- my testimony remains consistent -- should
22 more closely tie the review of integrated resource
23 planning and RFPs with appropriate levels of fuel risk
24 sharing.

25 Q. Thank you, Mr. Kalin.

1 Mr. Goggin.

2 A. (Witness Goggin) Yeah.

3 Q. On page 1, lines 14 to 17, you list
4 proceedings here in Georgia in which you have testified;
5 right?

6 A. (Witness Goggin) That's correct.

7 Q. But you've testified on behalf of different
8 parties in those proceedings; right?

9 A. (Witness Goggin) That's correct.

10 Q. In 2016, 2019, and the 2022 IRPs, you
11 testified for the Southern Renewable Energy Association;
12 is that correct?

13 A. (Witness Goggin) That's correct.

14 Q. And in the 2023 IRP update, in the 2025 IRP,
15 you testified on behalf of PIA Staff; right?

16 A. (Witness Goggin) That's correct.

17 Q. In this proceeding, you were appearing before
18 the Commission on behalf of SACE, Sierra Club and NRDC;
19 right?

20 A. (Witness Goggin) That's correct.

21 Q. Is it still fair to say that outside of your
22 appearances here in Georgia for PIA staff in 2023 and
23 2025, your testimony in all other jurisdictions has been
24 on behalf of special interest organizations, mostly
25 related to advocating for transmission related to

1 renewable energy?

2 A. (Witness Goggin) I would need to do a
3 detailed -- I do a lot of cases. Most is certainly that.
4 There are probably some exceptions where I've been working
5 for other parties, but I think most are that, yes. Like
6 transmission, you know, I mean, there's, you know,
7 consumer-oriented organizations. For example, in
8 Louisiana, I did a consumer organization, so there's a
9 mix.

10 Q. You have never operated a coal-fired or
11 gas-fired electric generating unit for the purpose of
12 retail electric service; is that true?

13 A. (Witness Goggin) That's correct.

14 Q. You have never worked for utility; right?

15 A. (Witness Goggin) That's correct.

16 Q. You have never served in a role that
17 dispatches electric generating units to serve customers
18 all over the state or within a group of states; is that
19 correct?

20 A. (Witness Goggin) That's correct.

21 Q. You have never run cost models for operating
22 and dispatching electric generating units, have you?

23 A. (Witness Goggin) I've directed the running of
24 production cost models, but not in an operational time
25 scale.

1 Q. You have never consulted on or been involved
2 with decisions on how to dispatch electric generating
3 units into vertically integrated retail electric systems;
4 have you?

5 A. (Witness Goggin) No, I have not.

6 Q. Okay. Would you agree that it's a complex
7 task?

8 A. (Witness Goggin) Sure. It's -- I mean,
9 that's why we use models for it.

10 Q. Right. And there are hundreds, maybe even
11 thousands, of inputs that operators need to consider in
12 dispatching generating units into a large electric system;
13 is that a fair statement?

14 A. (Witness Goggin) In a large system, yes.

15 Q. Would you consider the Southern Balancing
16 Authority at Georgia Power to be a large system?

17 A. (Witness Goggin) Sure. I mean, it depends on
18 what largest is, but yeah.

19 Q. As you note in your testimony, some of the
20 decisions include must-run requirements for things like
21 generator testing or minimum run times on coal units;
22 right?

23 A. (Witness Goggin) Yes. And I've already -- in
24 my summary I addressed both of those, and why, you know,
25 we've accounted for them and, you know, exclude them from

1 our disallowance.

2 Q. Right. There are also factors like system
3 reliability requirements; right?

4 A. (Witness Goggin) Yes. And that is reflected
5 in the must-runs that we accounted for. The transmission
6 constraints were anything that the company said was
7 must-run. Due to that, we exclude it from the analysis.

8 Q. Well, sometimes a utility must operate units
9 in a specific area for voltage support; right?

10 A. (Witness Goggin) Yes. And we asked about
11 that, and the response we got through discovery was the --
12 the must-runs for transmission constraints were clearly
13 identified and we exclude those from our analysis.

14 Q. The question wasn't for voltage support,
15 though. It was must-run -- day-ahead, must-run
16 transmission -- right? -- and that's the analysis you had
17 before you; right?

18 A. (Witness Goggin) That was what was given to
19 us, and I assumed that was inclusive of, like, local
20 reliability issues like voltage would be included in that,
21 in my understanding.

22 Q. Sometimes a unit must be dispatched so that
23 other available units can be held as operating reserves;
24 right?

25 A. (Witness Goggin) So operating reserves are,

1 you know, as you mentioned, it's something that's --
2 Southern is a large balancing area. And coal units are
3 not ideal providers of operating reserves in many cases,
4 you know. They're not particularly flexible or fast or
5 accurate at providing operating reserves. They can do it,
6 depending on, you know, certainly the slower reserves.

7 But reconstructing -- and I've done this in
8 other cases. Reconstructing what units were actually used
9 to provide operating reserves is extremely time intensive,
10 and the data is often not retained. And so it's something
11 that we did not include in our analysis.

12 It doesn't affect our analysis because the
13 periods we are looking at were basically low lambda
14 periods. That means that the marginal cost was low
15 because there's an abundance of resources relative to
16 demand. And in those conditions, the supply curve is very
17 flat. And there are a lot of resources that have headroom
18 to provide operating reserves. And so operating reserves
19 are not a binding constraint during those types of
20 conditions.

21 Q. There are also environmental limits on some
22 units, in which case other units must operate so that
23 certain units don't exceed their permit limitations with
24 other things; right?

25 A. (Witness Goggin) So we -- I think our

1 analysis adequately accounted for environmental limits,
2 first of all, and most importantly, our counterfactual is
3 de-committing these coal units, and that's going to reduce
4 emissions, like, that should improve their ability of the
5 coal units to comply with emissions limits.

6 The second point is, you know, we accounted
7 for the startup time, startup costs, and that, you know,
8 that's -- while that startup time or some of that startup
9 time is inclusive of the emissions controls, equipment,
10 things like that, the operating parameters that we used
11 that we got through discovery account for the emission
12 control limits.

13 And finally, again, these are light load
14 periods. They're not, you know, summer peak where you
15 often have, you know, like NOx emissions or things like
16 that that are binding. So I feel like these are
17 adequately accounted in analysis and should not be
18 significant binding factors.

19 Q. Yeah. My question was not about permit
20 conditions for startup, shutdown of coal plants. It was
21 just in general, in dispatching on a large system, you
22 have to take in environmental considerations and
23 limitations of all the units in deciding what to dispatch;
24 right?

25 A. (Witness Goggin) Yes. And that was the last

1 part of my answer, was that it was unlikely that those
2 would be binding during these periods.

3 Q. There are also considerations like overall
4 system management, right, where something like a peaking
5 gas plant or a hydro unit won't be operated during times
6 when they could be economic so that they are saved for
7 times when they are needed later; right?

8 A. (Witness Goggin) At the day-ahead timeframe,
9 I think that's -- I mean, yes, hydro, yeah, it's a
10 seasonal -- you know, you have some seasonal storage there
11 to some extent.

12 Q. It's also energy limited, right, because of
13 sometimes water flow issues or lake level issues; right?

14 A. (Witness Goggin) Yes. So I could see, you
15 know, for hydro, I mean, it is -- it can be a factor, but
16 again, it'd be like a much -- like on a day-to-day
17 commitment basis, should not be a binding factor. Same
18 with gas, you know, that's intraday. You've got gas in
19 the pipeline, and you're, you know, having to basically
20 balance supply and demand within that day.

21 So I don't think it's a major or certainly
22 even in that case probably even a significant impact on
23 the analysis. So I think, you know, again, like, we got
24 lambda data from the company, which I think is the best
25 metric we have of the value of generation on the day-ahead

1 timeframe when this decision was made. And I'm very
2 comfortable that that is the best metric, and we used it
3 appropriately to assess the company decisions.

4 Q. Yeah. And twice you said when the decision
5 is made. Are you aware that Southern Company dispatches
6 on an eight-day-ahead basis, not the day-ahead basis?

7 A. (Witness Goggin) I understand there's a
8 look-ahead, but the commitment decision, you know, based
9 on the startup limits, the time limits of the coal plants,
10 is day-ahead. Yes. You're looking over a longer horizon
11 and making decisions over that and thinking about and
12 updating your forecast continually over that time frame;
13 however, the go/no-go decision of do we start the coal
14 unit or not is day-ahead?

15 Q. On what basis do you premise that testimony,
16 because that is not correct based on the Southern Company
17 system. So what information are you basing commitment
18 decisions are made the day ahead?

19 A. (Witness Goggin) What I'm saying is, the
20 startup time information, which is confidential, but it is
21 consistent with a day-ahead-startup decision where
22 basically the -- if the coal unit is going to start, that
23 decision needs to be made a day ahead. Yes, I understand
24 you're doing eight-ahead, eight-day ahead, look-ahead, but
25 you're continually updating and making and changing

1 decisions throughout that, up until you get to a day-ahead
2 at coal units, when that is when you have to -- if you're
3 going to start it by the next day, that's when you have to
4 start it.

5 Q. A coal unit can't be started in less than a
6 day, but that doesn't mean that the decision of whether to
7 run it is made the day ahead, does it?

8 A. (Witness Goggin) If it is off, then the
9 decision needs to be made day-ahead.

10 Q. It must be made at least a day ahead to start
11 it up in time, but that doesn't mean the decision is made
12 or the planning for it is made the day ahead. That's the
13 distinction that I'm making that is different from your
14 testimony, and I want to make sure you understand that as
15 we go through the rest of the questions.

16 A. (Witness Goggin) Right. I mean, you have
17 the best -- the later, you wait, you have the best
18 information. And so your current decision is going to be
19 more optimal. You're going to have the best load
20 forecast, the best solar forecast, best market pricing
21 data day-ahead. And so you want to, you know, relative to
22 eight days ahead, and so you should be fine tuning your
23 decisions over that -- from eight day -- eight day to one
24 ahead. But then when you get to that one day ahead,
25 that's when you have to make that decision. Are we

1 committing it or not?

2 Q. I think --

3 A. (Witness Goggin) That's why we use that time
4 frame.

5 Q. I didn't mean to interrupt you.

6 I think the problem here is you seem to --
7 well, do you -- is it your understanding that Southern and
8 Georgia Power dispatch on day-ahead lambda based on
9 day-ahead lambda?

10 A. (Witness Goggin) No.

11 Q. Okay. Do you know what they dispatch on?

12 A. (Witness Goggin) Yes. I understand you have
13 a proprietary model that runs concurrently in dispatching.
14 And we asked through discovery about this, and it -- we
15 don't have access to it. So we created using day-ahead
16 lambda and extensive operating parameter data, a best
17 replication of that that we can do.

18 Q. So you created something different than what
19 Georgia Power has in terms of how they dispatch their
20 units?

21 A. (Witness Goggin) Out of necessity.

22 Q. Right. But then you are saying Georgia Power
23 is making imprudent decisions on how to dispatch based on
24 your model, not Georgia Power's model?

25 A. (Witness Goggin) Correct. Because this is

1 what we have.

2 Q. Now, your testimony claims that uneconomic
3 dispatch decisions were imprudent, but you do not discuss
4 the prudent standard in your testimony anywhere, did you?

5 A. (Witness Goggin) I'm not a lawyer, so I
6 didn't want to get into that.

7 VICE-CHAIRMAN MCDONALD: Mr. Chairman, would
8 you entertain a motion that we recess until 7:00 in
9 the morning?

10 MR. GOGGIN: I've got a flight tonight, if
11 it's at all possible for me to finish.

12 CHAIRMAN SHAW: Yeah. Let's try to keep it
13 going.

14 BY MR. HEWITSON:

15 Q. You're familiar with the fuel cost recovery
16 statute; right?

17 A. I'm not a lawyer, but I've heard enough
18 discussion today that I think I have general familiarity
19 with it.

20 Q. Okay. Well, are you aware that it provides
21 the Commission can disallow fuel costs that are the result
22 of illegal or clearly imprudent action by the company?

23 A. (Witness Goggin) That's what I've heard
24 today. Again, I'm not a lawyer, and I haven't
25 independently determined that.

1 Q. And you don't claim that the dispatch
2 decisions were illegal; right?

3 A. (Witness Goggin) I'm not saying that.

4 Q. Okay. And you don't address what it means to
5 be clearly imprudent in your testimony, either, do you?

6 A. (Witness Goggin) I'm not a lawyer. I'm
7 offering analysis that I think could inform lawyers and
8 the Commission to make that determination.

9 Q. Yeah. But you did say that there were
10 decisions that were imprudent. I'm saying, you did not
11 discuss what was clearly imprudent; right?

12 A. I'm sorry. Are you asking me did I define
13 imprudence?

14 Q. Did you define clearly imprudent?

15 A. (Witness Goggin) I did not attempt to.

16 Q. Do you agree that there are factors other
17 than the pure economics that the Commission should
18 consider when deciding whether a utility's dispatch of
19 units was prudent?

20 A. So, again, we've, I think, excluded from our
21 analysis, you know, the idea is that there's security
22 constrained economic dispatch. That's what the general
23 principle and the general terminology for what you're
24 talking about is, is where you must maintain reliability,
25 and then you economically dispatch to maintain

1 reliability. And so we took all of the things that were
2 identified as must-run reliability requirements out of the
3 analysis, so that we're basically trying to replicate what
4 was the -- once you've found the security constraints,
5 what is the economic dispatch, and that was why we did our
6 analysis that way.

7 Q. You took into consideration day-ahead
8 transmission identifications. Do you agree with me that
9 reliability is an important consideration for the company
10 and the Commission to consider?

11 A. Yes, and I believe that the reliability is
12 fully incorporated in those transmission designations. I
13 mean, that was why the company has them and uses them, if
14 that's -- if they need to go out of merit order, they do
15 that. And that's what we asked for and got in discovery,
16 and that was excluded from our analysis. Anytime they
17 went out of merit order through a must-run designation, we
18 exclude it from our analysis reflecting that, yes, that
19 would -- may or may not have been needed for reliability,
20 but we're going to take the company at its word that that
21 was needed for that.

22 Q. Okay. Do you agree that minimizing overall
23 cost to customers is important?

24 A. (Witness Goggin) Absolutely.

25 Q. Okay. Do you agree that maintaining a

1 diverse fleet of generation resources is also important?

2 A. (Witness Goggin) Certainly. I mean, on
3 the -- certainly on the planning time scale. On the
4 operating time scale, less important, because, you know,
5 if units start going down, you can bring up other units,
6 but yes.

7 Q. On page 4, lines 9 to 10, you mentioned that
8 solar and wind resources are typically dispatched first;
9 right?

10 A. (Witness Goggin) Correct.

11 Q. Solar and wind resources are not dispatched
12 like other resources, are they?

13 A. (Witness Goggin) I mean, they can be.

14 Q. Well, solar delivers energy when it's
15 available; right?

16 A. (Witness Goggin) Yes. But you can curtail
17 it down, if you'd like.

18 Q. You can curtail it down, but you can't
19 curtail it up?

20 A. (Witness Goggin) If it's already curtailed
21 down, you can curtail up, yes.

22 Q. You can't increase the amount of generation
23 you're getting from solar?

24 A. (Witness Goggin) If it was curtailed, you
25 can release the curtailment and it will go up.

1 Q. But if you're not curtailing it, you can't
2 increase the amount; right?

3 A. (Witness Goggin) Fair.

4 Q. And you can't tell it to start producing at
5 10:00 at night; right?

6 A. (Witness Goggin) That's correct.

7 Q. Okay. And you understand, I think, that
8 hydro facilities have some energy limitations and
9 operational aspects that have to be considered when
10 calling upon those units; right?

11 A. (Witness Goggin) Sure.

12 Q. Now, turning over to page 5, lines 2 to 6,
13 you discussed that uneconomic dispatch of coal can
14 displace lower cost resources like solar and hydro, but
15 you are speaking in hypothetical terms there; right?

16 A. Yes. And I think that, you know, likely did
17 occur on the system, given the amount of solar that is
18 present. And -- but, again, we -- you know, we weren't
19 able to get the company's model and replicate exactly, you
20 know, what was done.

21 Q. So when you say things like "likely did
22 occur," I have to ask you the follow-up question of, you
23 know, did your analysis or your work papers provide any
24 evidence that coal units were run out of economics and
25 displaced solar or hydro resources?

1 A. (Witness Goggin) So lambdas in many cases
2 were low enough that they could have reflected curtailment
3 of those resources. But, again, without access to the
4 company's models, we can't definitively say that.

5 Q. And your testimony does not provide any
6 evidence that coal units were dispatched in a way that
7 required curtailment of any solar PPAs; right?

8 A. Again, I think, you know, the lambda results
9 we have, and just the general system topology, I think
10 makes it likely, but I can't definitively say that.

11 Q. You didn't -- you don't have that analysis,
12 you didn't do that analysis, it would be speculation to
13 say that it did?

14 A. (Witness Goggin) Without access to the
15 company's models. I just can't prove that.

16 COMMISSIONER PRIDEMORE: Can I ask a
17 question?

18 MR. HEWITSON: Of course.

19 COMMISSIONER PRIDEMORE: In eight years, I've
20 never known at any one point in time where Georgia
21 Power has said they've curtailed solar. And when
22 you look at this, when you go to sysops and you
23 understand how the system operates, you recognize
24 that at the bottom of it is nuclear, your next
25 layer on top of it.

1 Think about it like making a sandwich,
2 Mr. Hewitson. I've got a piece of bread. That's
3 my nuclear. I'm putting a piece of cheese on
4 there. And for us, we've got about three pieces of
5 cheese, and that's our solar. And that gets us
6 where we need to go from, I don't know, but based
7 upon the time of year, about 7:30/8:00 in the
8 morning, until, I don't know, sometimes round 5:00
9 or 6:00 at night, depending upon the time of year.

10 And then you build dispatchable, all the
11 other operational generation assets on top of that,
12 based upon need, based upon demand.

13 So in eight years, I mean, could the company
14 answer that, if they've curtailed solar? It's just
15 more energy, just sell it. And that benefits
16 customers because they're getting the benefit of
17 the wholesale price.

18 MR. HEWITSON: I can't stand here and tell
19 you that 100 percent accuracy, it has never
20 happened, but you are absolutely right. That is
21 not a practice that happens in Georgia.

22 COMMISSIONER PRIDEMORE: Have either one of
23 y'all ever operated a system? Have you ever worked
24 within system operations before?

25 MR. GOGGIN: No, I've not been an operator.

1 COMMISSIONER PRIDEMORE: Okay. What about
2 you, Mr. Kalin?

3 MR. KALIN: It's not been the scope of my
4 responsibility, but certainly have had similar
5 exposure that -- that I think you've had in your
6 NARUC role, and as Commission, as a legislator on
7 the energy committee doing very detailed lawmaking.

8 COMMISSIONER PRIDEMORE: Well, I'm not an
9 engineer. I've never claimed to be, and I've never
10 been a sysops person. But I've been at this long
11 enough to understand the basics of how it operates
12 and knows how it works. I mean, you got that;
13 right? You know that -- you have -- you build your
14 generation assets based upon ones that are always
15 operating.

16 MR. KALIN: Well, one of the interesting
17 things that I learned in my time working with
18 MISO --

19 COMMISSIONER PRIDEMORE: I'm sorry about
20 that.

21 MR. KALIN: Was actually that by the time
22 that -- that I was involved in policymaking, and
23 left the legislature at the end of 2010, there was
24 enough wind geographically dispersed -- now, this
25 is wind, not time limited by solar, but it was

1 enough wind --

2 COMMISSIONER PRIDEMORE: I've got an apple.

3 I've got an orange.

4 MR. KALIN: Oh, hold on a second, though.

5 That was the -- that was the cool thing. There was

6 so much wind geographically dispersed that it had

7 become baseload equivalent. It was displacing

8 other baseload because of that diversity. The

9 question is, what other resources can we develop

10 here that can --

11 COMMISSIONER PRIDEMORE: In middle American

12 states --

13 MR. KALIN: -- technology questions.

14 COMMISSIONER PRIDEMORE: -- with flatland and

15 and rolling thousands of miles, I don't discredit

16 anything that MISO and SPP has with their wind

17 portfolio. But I welcome you to the north Georgia

18 mountains.

19 MR. KALIN: I love the north Georgia

20 mountains.

21 COMMISSIONER PRIDEMORE: I welcome you to the

22 flatlands of farm country in south Georgia, where

23 it's been tested and tried and tried and tested,

24 and it is not economical for us.

25 CHAIRMAN SHAW: I just want a --

1 COMMISSIONER PRIDEMORE: Curtailment on solar
2 is something -- this is -- we're -- we're down a
3 rabbit's hole that's not reality.

4 CHAIRMAN SHAW: You know, I'm trying to work
5 with y'all to get your client finished up, but we
6 all knew this thing was scheduled all day tomorrow,
7 so I'm trying. But that air turns off at 7:00, and
8 we're out of here, because I'm not going to make
9 everybody in here miserable just to finish.

10 COMMISSIONER HUBBARD: I don't mean to
11 belabor, but I'm seeing MRFH-4 that has a whole
12 list of solar curtailments, some of which have
13 reasons that have been discussed here. So, I mean,
14 I do see instances where solar is curtailed, and I
15 don't know the reasons for them fully, but --

16 MR. HEWITSON: Which is why, Commissioner
17 Hubbard, I said I couldn't have -- I couldn't say
18 at 100 percent certainty, but it's not a general
19 practice. It's not a general practice in other
20 states in which Mr. Goggin operates where there is
21 curtailment.

22 BY MR. HEWITSON:

23 Q. All right. Let's move to page 7 of your
24 analysis.

25 A. (Witness Goggin) Yep.

1 Q. Lines 4 to 7, you explain your methodology
2 where you say that if an operating coal unit's marginal
3 costs was higher than system lambda, it indicates the unit
4 was uneconomic to operate and the company incurred a loss.

5 That's the premise of your testimony; right?

6 A. (Witness Goggin) Yes.

7 Q. Okay. But you did not analyze the potential
8 cost of not operating the unit during that hour, did you?

9 A. (Witness Goggin) No, so this is the marginal
10 cost. And, yes, as you kind of construct a counterfactual
11 and move away from that margin, it's, you know,
12 constructing counterfactuals is hard. There's no data in
13 the counterfactual world. But what you do know is that,
14 again, these are low lambda periods that reflect that
15 supply is abundant relative to demand. And, you know,
16 going back to the supply curve we've been talking about,
17 when you're on that left side of the supply curve, when
18 supply is abundant, there are -- if the supply curve is
19 flat and it's low cost. And so there's a lot of resources
20 available in those periods. And so the assumption is that
21 the marginal -- as you move away from that margin, that
22 the costs are generally close to what you were on, what
23 the price was at that margin.

24 Q. And we've already discussed this, but just to
25 set up my next questions. You're aware that hourly lambda

1 is different than the full production cost model; right?

2 A. (Witness Goggin) Sure.

3 Q. And the production cost model is more
4 complete; right? Do you understand that it also includes
5 the cost of reserves on the system?

6 A. (Witness Goggin) Yes.

7 Q. Okay. There are all types of reserves;
8 right?

9 A. (Witness Goggin) Yes. And we talked about
10 this before, you know. Again, when you're on this left
11 side of the supply curve, operating reserves and headroom
12 are cheap and abundant.

13 Q. When units are in reserve, they are available
14 to serve customers in the event of lost generation or
15 transmission outages or increasing customer demand; right?

16 A. (Witness Goggin) That's correct.

17 Q. Okay. Do you recognize that day-ahead lambda
18 is an output of the production cost optimization model?

19 A. (Witness Goggin) Yes.

20 Q. Okay. Day-ahead lambda is calculated
21 assuming the units are online and available for reserves;
22 right?

23 A. (Witness Goggin) Yes.

24 Q. In other words, the historical day-ahead
25 lambda already assumes whether the coal units are

1 committed; right?

2 A. (Witness Goggin) That's correct.

3 Q. So you're aware that some coal units like
4 Plant Bowen have 168-hour-minimum downtime; right?

5 A. (Witness Goggin) I believe you're saying
6 minimum uptime.

7 Q. No, I'm saying minimum downtime. Once you
8 take it down, it must be off for seven days before it can
9 be brought back up.

10 A. I believe you provided that number as minimum
11 uptime in discovery.

12 Q. Let me put it this way, then. You agree that
13 once you take it offline, it's got to stay off for seven
14 days?

15 A. (Witness Goggin) The constraints you gave
16 us, which I believe was that one, we -- for every year we
17 incorporated them.

18 Q. Okay. Regardless, it's more than a day;
19 right?

20 A. (Witness Goggin) Yes.

21 Q. All right. And that makes sense, which is
22 why commitments are made more than a day in advance;
23 right?

24 A. Right. And those operating constraints, that
25 seven days, that was accounted for fully in our analysis.

1 Q. So if day-ahead lambda is calculated assuming
2 certain coal units are online, it doesn't make sense to
3 use that value to determine whether the same coal units
4 should be committed, does it?

5 A. (Witness Goggin) Again, we're looking at the
6 marginal value. The lambda is a marginal -- a proxy for
7 the marginal value, and it reflects that -- again, as
8 close as we can get to where we were trying to figure out
9 if we took this coal unit out and replaced it, what would
10 that cost? And that day-ahead Lambda is the best metric
11 we have for that, and that's why we used it.

12 Q. And that's kind of the point, Mr. Goggin, is
13 the best metric that you have, but it's not the accurate
14 measure -- it's not the accurate metric if day-ahead
15 lambda doesn't include the units that are on reserve at
16 the time, does it?

17 A. (Witness Goggin) Again, we're on the left
18 side of the supply curve. It's very flat, very cheap. So
19 it doesn't move around that much, you know, it's a flat
20 supply curve. You can move megawatts and gigawatts and it
21 doesn't move. The price does not move. And that's why
22 it's an adequate metric.

23 Again, I would love to have had access to
24 your models and fully replicate exactly what you do. We
25 didn't have that, and so we did the second-best thing we

1 can do, we used day-ahead lambda, as the best proxy, which
2 is a really good proxy in this situation, on this left
3 side of the supply curve where we are.

4 Q. You say it's a really good proxy, but it
5 ignores the cost of the units that are on reserve at the
6 time, right, that are committed for reserve purposes, not
7 for serving customers. So then you take lambda and you
8 say, and that production cost model, which includes
9 reserves, which coal plants are part of and calculated in
10 that, in that metric, in that cost, you then say, well, if
11 you take the coal plan out, what does lambda say? But
12 lambda is calculated assuming the coal plants are there.

13 A. (Witness Goggin) Right.

14 Q. The counterfactual doesn't work in that
15 situation, does it?

16 A. (Witness Goggin) It's very close. And,
17 again, it can go either way. And it's a -- and the
18 operating reserves is also -- I mean, those are held as
19 headroom on the resources. So it's the same, you know,
20 again, they're -- within the resource, their supply curve
21 is also flat, particularly at this, you know, this part of
22 the dispatch curve. And so these things are all very
23 close. They're not going to change.

24 You know, the findings we have, \$152 million
25 is very large. These minor differences at the margin,

1 which is literally where we are, we're talking about, you
2 know, moving a little bit around the margin, are not going
3 to erase that \$152 million.

4 Q. It's really hard for this Commission to take
5 testimony from somebody that says: Well, we didn't do the
6 exact right model. We didn't have the information to do
7 the model, but you should still disallow \$152 million
8 based on analysis that I admit was using the wrong
9 information.

10 A. If you gave us the model you used, we would
11 have loved to have run that. We couldn't get it, and so
12 we did the best we could. And I think it's very close.
13 It's certainly not going to erase \$152 million if we used
14 your model.

15 Q. Did you calculate what happens to lambda when
16 you take the coal units offline?

17 A. (Witness Goggin) We couldn't reconstruct
18 that without your model.

19 Q. Okay. So if coal units are not available as
20 reserves, the company would need to rely on something
21 else? Another, presumably, more expensive unit; right?

22 A. (Witness Goggin) As I said, we're on the
23 left side of the supply curve. This is periods when
24 lambda is low and the supply curve over there is flat.
25 And so you can move around quite a bit on the quantity

1 side, and the price doesn't change that much.

2 Q. That's not my question. If you remove the
3 coal units, you don't know what happens to you lambda, but
4 you know presumably it goes up; right?

5 A. (Witness Goggin) Right. And I'm saying it
6 doesn't change much.

7 Q. Based on what?

8 A. What the supply curve looks like. I know
9 that.

10 Q. But did you run that analysis?

11 A. (Witness Goggin) I can look at the supply
12 curve and tell you it's flat.

13 Q. That's not the question. Did you run the
14 analysis?

15 A. Reconstructing a detailed counterfactual with
16 this is not possible.

17 MR. HEWITSON: Thank you. No further
18 questions, Mr. Goggin.

19 CHAIRMAN SHAW: Redirect.

20 MS. ARIZA: Thank you.

21 REDIRECT EXAMINATION

22 BY MS. ARIZA:

23 Q. Just one question for Mr. Goggin. Georgia
24 Power's counsel just asked about the model you replicated
25 to come up with the day-ahead analysis. Do you think your

1 analysis is still adequate, even though it doesn't use
2 Southern's model?

3 A. (Witness Goggin) Absolutely. Again, you
4 know, \$152 million in net repair costs here is a -- is a
5 huge amount, and it is insensitive to minor changes in the
6 assumptions and inputs.

7 Again, I would have loved to have had access
8 to the company's model and fully replicate exactly what
9 they do. We did the best replication we could of that
10 with the data we had. And I'm confident that these minor
11 deviations, you know, things like operating reserves,
12 which are typically ignored in production cost models,
13 these are minor aspects that are not going to change the
14 fundamental conclusion that they were very large net cost
15 to ratepayers from uneconomic coal dispatch.

16 MS. ARIZA: Okay. Thank you.

17 I move their exhibits and testimony into the
18 record.

19 CHAIRMAN SHAW: So marked.

20 (SIERRA CLUB/SACE/NRDC Exhibits 1 through 11
21 were admitted into evidence.)

22 COMMISSIONER HUBBARD: Mr. Hewitson, was
23 there a reason why you weren't able to provide that
24 model to Witness Goggin? And are you able to
25 provide that to staff?

1 MR. HEWITSON: The production cost models are
2 a proprietary model that Georgia Power uses. I
3 don't know if staff has ever asked for it.
4 Mr. Goggin is representing SACE and Sierra Club and
5 doesn't have access. And if I'm correct, and
6 somebody tomorrow can probably correct me if I get
7 this wrong, it's not like an off-the-shelf software
8 that you can just hand to someone and let them run
9 the models. It is Southern Company's proprietary
10 system of how they operate, how they operate the
11 system.

12 COMMISSIONER HUBBARD: But even if it were
13 provided, maybe not in an operational mode, this
14 model, just something where you could see inputs,
15 outputs, is that possible?

16 MR. HEWITSON: I don't know if that's
17 possible. I don't know if staff has asked for it
18 in this case, and we certainly didn't know what
19 Mr. Goggin's testimony was going to be prior to
20 him --

21 COMMISSIONER HUBBARD: Okay.

22 MR. HEWITSON: And sorry for not coming to
23 the podium.

24 MS. ARIZA: Thank you, Chairman Shaw. I was
25 just asking for their exhibits and testimony to be

1 moved into the record.

2 CHAIRMAN SHAW: So marked.

3 And, gentlemen, thanks for hanging with us.

4 MR. GOGGIN: Yeah. Thanks for accommodating

5 your flight. I appreciate it.

6 CHAIRMAN SHAW: Glad you can make your

7 flight.

8 MR. GOGGIN: Yeah. Thank you.

9 CHAIRMAN SHAW: Y'all are excused. We'll see

10 everyone tomorrow.

11 COMMISSIONER PRIDEMORE: Safe travels.

12 CHAIRMAN SHAW: 9:30 in the morning.

13 (Hearing adjourned at 7:01 p.m.)

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C E R T I F I C A T E

We, Brenda P. Elwell and Kelley M. Nadotta,
Certified Court Reporters, do hereby certify that the
foregoing transcript is an accurate record of the
proceedings had in the above-entitled matter at the time
and place therein set forth.



Kelley Marie Nadotti, RPR, CCR
CCR 6256-8388-8026-4192



Brenda P. Elwell, RPR, CCR, B-2023