BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

* * *

In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements With Qualifying Facilities

Docket No. 15-035-53

~~~~~~

HEARING PROCEEDINGS

PRESIDING OFFICER THAD LAVAR

~~~~~~

TAKEN AT: Public Service Commission
Hearing Room 403
160 East 300 South
Salt Lake City, Utah

DATE: Thursday, November 12, 2015

TIME: 9:03 a.m.

REPORTED BY: Clark L. Edwards, Utah CSR #109221-7801

Job No.: 262985

A P P E A R A N C E S

THE HEARING OFFICER: THAD LAVAR
COMMISSIONER DAVID CLARK
COMMISSIONER JORDAN WHITE

FOR ROCKY MOUNTAIN POWER COMPANY:

YVONNE R. HOGLE, ESQ.
201 South Main Street, Suite 2400
Salt Lake City, Utah 84111

FOR DIVISION OF PUBLIC UTILITIES:

JUSTIN C. JETTER, ESQ.
ASSISTANT ATTORNEY GENERAL
160 East 300 South, Fifth Floor
Salt Lake City, Utah 84114

FOR OFFICE OF CONSUMER SERVICES:

ROBERT J. MOORE, ESQ.
ASSISTANT ATTORNEY GENERAL
160 East 300 South, 5th Floor
Salt Lake City, Utah 84114

FOR UTAH CLEAN ENERGY:

MEGHAN E. DUTTON, ESQ.
1124 East Tulane Circle
Sandy, Utah 84094

FOR ROCKY MOUNTAIN COALITION
FOR RENEWABLE ENERGY (RMCRE)
AND SUN EDISON:

GARY A. DODGE, ESQ.
HATCH, JAMES & DODGE, P.C.
10 West Broadway, Suite 400
Salt Lake City, Utah 84101

FOR RENEWABLE ENERGY COALITION:

ADAM S. LONG, ESQ.
SMITH HARTVIGSEN PLLC
175 South Main, Suite 300
Salt Lake City, Utah 84111

IRION A. SANGER (Oregon)

A P P E A R A N C E S
(Continued)

FOR THE SIERRA CLUB:

TRAVIS RITCHIE, ESQ.
THE SIERRA CLUB
85 Second Street, Second Floor
San Francisco, California 94105

I N D E X

I N D E X
(Continued)

E X H I B I T S

NUMBER	DESCRIPTION	MARK	ADMIT
RMP EXHIBIT-1	Direct, Rebuttal, and Surrebuttal Testimony of Paul Clements	11	11
OSC EXHIBIT-1	Docket 15-305-70 Statement of Paul Clements	24	28
RMCRE Cross EXHIBIT-1	Docket No. 03-035-14 Excerpt	68	--
RMCRE Cross EXHIBIT-2	Utah Hedging Collaborative Report	75	84
DPU	Direct, Rebuttal, and Surrebuttal Testimony of Charles Peterson	115	116
RMCRE Cross EXHIBIT-3	Yieldco Articles	136	139
REC EXHIBIT-1	John Lowe Declaration Kevin Higgins' Testimony	153	160
REC `	Testimony of John Lowe	163	163
REC	Rebuttal Testimony of Nathan Rich	167	168
OCS	Direct, Rebuttal, and Surrebuttal testimony of Bela Vastag	176	176
UCE EXHIBIT-1	Direct Testimony of Sarah Wright	184	185
UCE EXHIBIT-2	Surrebuttal Testimony of Sarah Wright	184	185
TSC	Direct Testimony and Exhibits, R. Thomas Beach	202	203
RMCRE EXHIBIT 1.0	Kevin Higgins Direct Testimony	230	231
RMCRE EXHIBIT 1.0SR	Kevin Higgins Surrebuttal Testimony	230	231

E X H I B I T S
(Continued)

NUMBER	DESCRIPTION	MARK	ADMIT
RMCRE EXHIBIT 2.0	Bryan L. Harris Direct Testimony	238	238
RMCRE EXHIBIT 2.0R	Bryan L. Harris Rebuttal Testimony	238	238
RMCRE EXHIBIT 2.0SR	Bryan L. Harris Surrebuttal Testimony	238	238
RMCRE EXHIBIT 3.0	Hans Isern Direct Testimony	257	258
RMCRE EXHIBIT 3.0R	Hans Isern Rebuttal Testimony	257	258
RMCRE EXHIBIT 3.0SR	Hans Isern Surrebuttal Testimony	257	258

P R O C E E D I N G S

THE HEARING OFFICER: Good morning. We are here in the matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities.

This is Public Service Commission Docket Number 15-035-53. And why don't we start with appearances from the utility.

MS. HOGLE: Good morning, commissioners, parties and spectators. My name is Yvonne Hogle. I am here on behalf of Rocky Mountain Power. With me here today is Mr. Paul Clements. Thank you.

THE HEARING OFFICER: Okay. Thank you.

The Division?

MR. JETTER: Thank you. I'm Justin Jetter with the Utah Attorney General's Office. I represent the Utah Division of Public Utilities. And with me at counsel table is Charles Peterson with the Utah Division of Publicly Utilities.

MR. MOORE: Bob Moore representing the Office of Consumer Services. With me is Bela Vastag, a utility analyst at the Office of Consumer Services.

THE HEARING OFFICER: Okay. Thank you.

MS. DUTTON: Good morning. I'm Meghan Dutton representing Utah Clean Energy. And with me is our expert Sarah Wright.

THE HEARING OFFICER: Thank you.

MR. RITCHIE: Good morning commissioners. Travis Ritchie representing the Sierra Club. And with me in the audience is Tom Beach.

THE HEARING OFFICER: Thank you.

MR. DODGE: Thank you. I'm Gary Dodge on behalf of the Rocky Mountain Coalition for Renewable Energy.

THE HEARING OFFICER: Okay. Thank you.

MR. SANGER: Irion Sanger here on behalf of Renewable Energy Coalition. We have two people here today. One of them is here today, Nathan Rich, and John Lowe will be joining us very shortly.

THE HEARING OFFICER: Okay.

Is that all for the appearances? No one else in the room that wasn't able to fit at the tables?

MR. LONG: I'm Adam Long. I'm local counsel for the Renewable Energy Coalition.

THE HEARING OFFICER: Okay.

MR. LONG: Mr. Sanger will be essentially the face of it today.

THE HEARING OFFICER: Thank you. Anyone else? Any other preliminary matters before we start? I'm not seeing any. So, we'll turn to the utility.

MS. HOGLE: Thank you. The Company calls Mr. Paul Clements.

THE HEARING OFFICER: Mr. Clements, do you swear to tell the truth?

MR. CLEMENTS: I do.

THE HEARING OFFICER: Thank you.

PAUL CLEMENTS,

having first been duly sworn, was

examined and testified as follows:

DIRECT EXAMINATION

BY MS. HOGLE:

Q. Good morning, Mr. Clements.

A. Good morning.

Q. Can you please state and spell your name for the record and your position?

A. Yes. My name is Paul Clements, C-l-e-m-e-n-t-s. And I'm currently Director of Commercial Services for Rocky Mountain Power.

Q. And can you provide a brief background for the commissioners today?

A. Certainly. I've worked for PacifiCorp for over close to 11 years at this point. Primary responsibilities include negotiating qualifying facility contracts and negotiating other wholesale energy supply contracts in addition to negotiating large special contracts with our large industrial customers.

(Direct, Rebuttal, Surrebuttal Testimony of Paul Clements identified).

BY MS. HOGLE:

Q. In that capacity, did you prepare direct testimony with attached Exhibit-A, rebuttal testimony, and surrebuttal testimony in support of the Company's application in this case?

A. Yes, I did.

Q. And do you have any changes or edits to that testimony?

A. I do not.

Q. So, if I were to ask you the questions in those pieces of testimony again here today, would your answers be the same?

A. They would.

MS. HOGLE: I move for the admission into the record of the Company's, specifically Mr. Clements' direct testimony in Exhibit-A, rebuttal testimony, and surrebuttal testimony.

THE HEARING OFFICER: I'll ask any party to indicate if you have an objection to that. And not seeing any, that will be entered. Thank you.

(Direct, Rebuttal, Surrebuttal Testimony of Paul Clements Admitted)

BY MS. HOGLE:

Q. Thank you. Mr. Clements, do you have a summary that you would like to provide today?

A. I do.

Q. Please proceed.

A. Good morning. I'll try to keep my summary brief while covering the important issues before us today. So, the purpose of my testimony is to support and to present the Company's application to modify the maximum allowable contract term for qualifying facility or QF contracts that the Company must enter into under the Public Utility Regulatory Policies Act of 1978 also known as PURPA.

The Company is seeking a modification to the maximum contract term of QF contracts executed under both Schedules 37 and 38.

Specifically, the Company is requesting the maximum contract term for PURPA contracts be reduced from the current 20 years to three years.

I'd like to talk a little bit about why this change is needed at this time. You may be thinking as many of us have that the Commission has already addressed just about every QF issue under the sun in the various dockets that we've had over the past several years.

And, in fact, the Commission addressed the issue of a QF avoided cost or the price in Docket 03-035-14 and Docket 12-035-100.

I personally used to be of the opinion that if the QF price is set correctly, then the contract term does not matter.

However, my opinion changed on that matter. When I further evaluated how QF contracts compared to non-QF contracts that the Company enters into, I determined that a 20-year QF contract term does not meet the ratepayer indifference standard required by PURPA because it exposes customers to risks that they otherwise would not be exposed to absent the QF contract.

Let's talk a bit about the ratepayer indifference standard.

So, the ratepayer indifference standard or the avoided cost standard is intended to leave customers economically indifferent to the source of the utility's energy by ensuring that the cost to the utility of purchasing from a QF does not exceed the cost the utility would incur if it purchases from another source.

The 20-year contract term does not meet this ratepayer indifference test for the following three reasons. First, it is inconsistent with the Company's hedging practices which were implemented after a careful review by stakeholders through a recent collaborative.

Second, it is inconsistent with resource acquisition policies and practices for non-PURPA energy purchases.

And third, it is not aligned with the Company's IRP or integrated resource plan, planning cycle, and action plan.

This is a critical issue to protect customers. At the time my testimony was prepared, PacifiCorp had 1,041 megawatts of existing PURPA contracts in Utah and 2,253 megawatts of proposed QF contracts in Utah.

So, together, that's 3,294 megawatts of existing and potential Utah QF contracts. PacifiCorp's average Utah retail load in 2014 was 2,959 megawatts.

So, we have more existing and proposed, at the time of the filing, more existing and proposed QF contracts than the average Utah retail load. We're talking about a lot of megawatts at stake.

Now let's talk about the dollar impact.

The expected system-wide costs or payments to QFs over the next ten years just from the executed QF contracts, so these are contracts that are already signed, is $2.9 billion.

So, that's $2.9 billion in QF payments over the next ten years. In 2015 alone, the projected payments are 170.5 million and Utah's share of that is

$73.3 million. So, Utah customers are projected to pay $73.3 million to QFs in 2015.

I highlight that to illustrate that QF contracts are a major factor in customers' rates.

Now, let's talk a minute about the first point which is the 20-year QF contract term is inconsistent with the Company's hedging practice and policy.

The Company modified its hedging horizon for natural gas and electricity trades and other commodities as a result of a hedging collaborative and workshops that were held in 2011 and 2012.

That collaborative convened as a result of concerns expressed by the DPU, the Office, and various other parties about some hedges the Company had entered into. In its report on the collaborative, the DPU stated the following in part:

"Because of relative market illiquidity and potential inaccuracy of the forecasted demand requirements, hedges should normally be limited to 36 forward months."

PacifiCorp's current practice which was implemented as a result of the hedging workshops is to actively manage electricity and natural gas positions that are 36 months out and nearer, meaning from today out three years. What does that mean?

That means that the Company would not and arguably could not under its existing policies enter into a 20-year contract to purchase electricity from a counterparty who is not a QF. Our policy prohibits it.

And we do not enter into 20-year contracts to purchase natural gas. Again, the policy prohibits it as a result of the hedging collaborative.

But the Company must enter into an unlimited amount of 20-year fixed-price contracts with QF counterparties. That is inconsistent with the hedging practice and policy for non-QF contracts.

I'd like to throw out an example of how this inconsistency is occurring in practice.

So, the Company cannot without extensive stakeholder interest and review enter into a 20-year hedge for natural gas at one of its power plants like Lakeside. Under the avoided cost method, a QF may displace or avoid the operation of that very same gas plant, Lakeside, let's call it.

To calculate the avoided cost at Lakeside, the Company utilizes its production dispatch model and forecasts out the cost of gas for 20 years.

So, if you have a seven heat rate at Lakeside and the cost of gas is $3 per an MBTU, then the model would say that the cost of production at Lakeside is

$21 plus some variable 0 and M. So, seven heat rate times a $3 gas price. If the QF avoids Lakeside over the entire 20 years, the QF would get a $21 plus the variable 0 and M, $21 avoided cost price. If the QF executes that 20-year contract at that price, the Company is effectively locking in the cost of gas for 20 years.

In theory, Lakeside would not be operated and the Company would purchase the energy from the QF at that $21 price. If gas prices were to drop to $2 per MMBTU, without the QF, the Company would operate Lakeside at $14 per megawatt hour and achieve that difference in price.

However, since a 20-year contract was signed with the QF, the Company is locked into a gas price for 20 years. So, under a normal hedging policy and practice, the Company would not hedge the price of gas for 20 years.

However, under a QF contract, the Company may be forced to do so. The 20-year QF contract term therefore introduces the Company's customers to long-term fixed-price risk that it otherwise would not occur.

Now, let's talk a little bit about what is fixed-price risk and why does it matter.

The Company and its customers are not commodity traders. The Company hedges to reduce or to eliminate volatility in the near term.

The Company does not engage in speculative trading. Speculative trading attempts to profit from betting on the direction in which a market will move. The longer the time horizon, the more likely your bet will be wrong.

For example, you can probably forecast with relative accuracy the price of gasoline for next month. It will probably be $2, $2.20 per gallon. I think we can feel somewhat confident about that.

However, if we were to try to predict today what the price of gasoline will be 20 years from now, our prediction will likely be materially wrong. This concept represents fixed-price risk.

Here is an example of how the 20-year contract, 20-year QF contract has exposed customers to increased fixed-price risk.

The Company currently has 1,991 megawatts of nameplate capacity QF contracts. That was at the time I prepared this filing. It's changed slightly since then.

Over the next ten years, the Company is under contract to purchase 44.6 million megawatt hours under these contracts. The average price for these contracts is $64.13 per megawatt hour.

The average forward price curve for mid-Columbia, a major trading hub in the Northwest over this same ten-year time period $38.11 per megawatt hour. That is a difference of $26.02 per megawatt hour or that equates to $1.2 billion over this ten-year time period.

So, if you compare the price of the QF contracts that we've entered into recently to the price at Mid-Columbia over the next ten years, it's $1.2 billion out of the money.

Now, I acknowledge and completely agree that that could just as easily be $1.2 billion in the money. The market could just as easily have moved in the opposite direction.

I'm not concerned about placing a bet and being right or wrong. The issue is fixed-price risk. And that example illustrates that once you enter into a long-term contract, you are automatically exposed to a considerable amount of fixed-price risk. And our stakeholders made it clear that we should manage that fixed-price risk by limiting our contracts to 36 months or less in duration.

Briefly touching upon my second point, and that is, QF contracts do not go through the same rigorous acquisition process as non-QF contracts, when the Company determines that it needs to enter into a long-term contract, it's usually the result of a need identified in the Integrated Resource Plan.

The Company then performs an extensive analysis to compare the contemplated transaction to other available transactions and it does an extensive review of the credit terms, contract terms, and the needs assessment of the Company.

Most importantly, the Company utilizes a rigorous request for proposal or RFP process whenever it acquires a long-term resource.

PURPA contracts do not go through that same request for proposal process and the same rigorous review process because the Company must execute the contract.

On to my last point, and that is that the 20-year QF contract term is inconsistent with IRP timelines. So, some parties argue that my point that we should look at our hedging policy as not relevant. They argue that a QF contract is more like a Company resource that we inquire through the IRP. It is not.

First of all, the Company does enter into a long-term transaction unless there is a need identified in the IRP. Now, the IRP goes out 20-plus years and it acknowledges that the planning uncertainties grow as you get further out in time.

It is for that reason that the IRP action plan is focused only on the next two to four years.

So, the IRP says, here's what we expect you will need over the next 20-plus years. But it says, here's what you need to do over the next two to four years. So, what does that mean?

Currently, the 2015 IRP has identified a need for a natural gas plant in 2028. However, the IRP action plan does not have the Company go out and acquire that resource today because that resource is not needed for another 13 years. The IRP action plan says, only take action that's needed in the next two to four years.

Now, why is that important? Well, let's talk about a real-world example. The 2013 IRP which was just two years ago had a gas plant in 2024.

The 2013 IRP update which would have been a year ago moved that gas plant out to 2027. That was a result of changes in load and other factors in the IRP.

The 2015 IRP pushed that gas plan further out to 2028. So, there we see that over a two-year time period, the Company's resource need changed by four years. Now, why does that matter to QF contracts?

Had the Company entered into a 20-year contract with a QF based on the assumption that a resource was needed in 2024, the Company would be locked in to paying that capacity payment starting in 2024.

The Company wasn't planning to go out and build that 2024 resource, but if it signed this QF contract, it's now locked into paying that capacity payment.

That's a mismatch. Customers are exposed to locking in costs in the future that they otherwise would not be locked into under the current IRP action plan.

That mismatch does not meet the ratepayer indifference standard that's required by PURPA.

The Company's proposal to limit QF contract terms to three years is aligned with that two- to four-year action plan.

Now, I'll touch briefly -- I'm very close to being done. I'll touch briefly on a few of the comments from the other parties in this docket.

Many of the intervenors carry common themes in their responses to the Company's application. Many parties suggest that we're trying to eliminate the must-purchase obligation.

That's simply not true. My testimony is clear that the must-purchase obligation remains. Many of these parties suggest that a QF is not similar to a commodity hedge but instead is more like a company resource.

However, it's clear that a 20-year QF contract is a purchase of energy at a fixed price. That is a commodity hedge. These parties suggest as I mentioned that a QF contract is similar to a company resource.

But a company only acquires a resource if a need is identified in the IRP and then the company goes out and acquires just what is needed at the time it is needed. Also, a company resource can be dispatched down.

So, if there is a more economic option, it'll dispatch the unit down and take advantage of that more economic option where a QF contract is a must-take for the Company.

Lastly, some of the parties have suggested that QFs are a good hedge because they can meet future environmental compliance obligations.

Now, we don't know what those future environmental obligations currently are. They are not known and measurable. And more importantly, these parties ignore the critical fact that the QF retains the renewable energy credit or the environmental attribute for their economic benefit.

Those RECs represent the very environmental benefits or attributes that these parties are touting as being beneficial to the Company. The Company doesn't actually receive those.

In summary, no party has provided credible evidence to refute the three key points made the Company in this proceeding. First, the 20-year contract term is inconsistent with the Company's hedging policy.

Second, the 20-year contract term is inconsistent with the Company's resource acquisition practice for non-PURPA energy purchases.

And lastly, that the 20-year contract term is not aligned with the IRP action plan.

I continue to recommend that the Commission implement the three-year contract term for all QF contracts, again, both those executed under Schedule 37 and Schedule 38. And that concludes my summary.

MS. HOGLE: Thank you, Mr. Clements. Mr. Clements is available for cross-examination.

THE HEARING OFFICER: Thank you.

Before I go to the Division and then to the Office, I do want to briefly ask Ms. Dutton, Mr. Ritchie, Mr. Dodge, and Mr. Sanger if, when we get to this point, do the four of you have a preference in terms of order of cross-examination or should I just go in the order that you're seated?

(Discussion off the record)

THE HEARING OFFICER: Okay. Thank you.

Mr. Jetter?

MR. JETTER: Thank you. The Division has no cross-examination questions for Mr. Clements.

THE HEARING OFFICER: Thank you. Mr. Moore.

(OSC Exhibit-1 identified)

CROSS-EXAMINATION

BY MR. MOORE:

Q. The Office has just two areas of inquiry.

Mr. Clements, two days ago last Tuesday, you participated in a hearing in Docket 15-305-70 concerning an application for approval of a PPA which has some overlap with this case; isn't that correct? Factual overlap.

A. You'll have to expand on the overlap that you're referring to.

Q. All right. I'll get to that.

During the hearing you submitted some comments that you participated in preparing and adopted them as your sworn testimony; wasn't that correct?

A. That's correct.

MR. MOORE: I have some copies of these comments here. Can I pass them out the now?

THE HEARING OFFICER: Any other party, let me know if you have an objection.

MS. HOGLE: The Company has an objection. And the objection is that I believe whatever he's going to be introducing is probably outside the scope of this docket.

THE HEARING OFFICER: Mr. Moore?

MR. MOORE: I'll connect that up.

Mr. Clements spoke about -- one of the issues in this docket is the threat of overwhelming QF contracts in the future. The discussion in the hearing on Tuesday touched upon that issue.

THE HEARING OFFICER: Have you distributed this to the other parties?

MR. MOORE: I have not yet but I have them right here.

THE HEARING OFFICER: Why don't you do that. Why don't you distribute it to the other parties and then we'll deal with the objection and see if anyone else wants to weigh in.

(Document distribution by Mr. Moore)

THE HEARING OFFICER: Let me just ask, Mr. Hogle, do you want to say anything else to your objection after looking at that or are you familiar enough with it to say anything you need to?

MS. HOGLE: I would like to add to the objection that from Mr. Moore's response, he indicated that it was -- I'm not sure he said it was relevant, but he did indicate that the comments in the proceeding two days ago had a bearing on the number of PPA contracts that we were discussing in this case and the volume. And I don't recall that being an issue in that case.

MR. MOORE: I would direct Ms. Hogle to page four, the first full paragraph, and the first two sentences.

THE HEARING OFFICER: Mr. Moore, I think I'm going to let you go ahead with this line of questioning and we'll see where it goes subject to more specific objection as you move forward. So, I think we'll just proceed that way.

BY MR. MOORE:

Q. Mr. Clements, you have a copy of these?

A. I do, yes.

Q. Could you please turn to page four?

A. Okay.

Q. The first two sentences in the first paragraph three: "The Company routinely manages between ten and 22 negotiations at any given time. In the early and mid 2015, the Company was managing 170 different QF pricing requests and negotiation.

"The large increase is primarily attributable to the solo projects attempting to execute a contract in the time to allow them to build a project by the end of 2016 in order to take advantage of expiring federal investment tax credit."

Is that still your testimony today?

A. Yes.

MR. MOORE: I would like to enter these comments into evidence at this time?

THE HEARING OFFICER: And your motion is for the entire document, not just the portion that was read?

MR. MOORE: Well, I have the entire document, yes, but the portion as read is the only portion I'll be inquiring into.

THE HEARING OFFICER: Okay.

Any objection to that motion?

MS. HOGLE: The Company renews its objection. Thank you.

THE HEARING OFFICER: Any other party have any position on that?

MR. DODGE: I believe you can take administrative notice of testimony in the record before you in another docket.

So, it could be admitted, but either way, I think you have the right to rely on it and look at it.

THE HEARING OFFICER: Any other comments?

I think from a practical matter, the three of us are pretty familiar with this other docket. I think the prudent course is to allow this in and we'll take appropriate administrative notice of it considering that they are two separate dockets but we'll continue forward. Thank you. Mr. Moore.

(OCS Exhibit-1 Admitted)

BY MR. MOORE:

Q. Now, the 107 contract requests are only the ones active in the last six months. There are more QF contract requests than the 107 in the last two years that's at issue in this case; isn't that correct?
A. I wouldn't say that what's occurred over the past two years is what's at issue in this case, but the fact that there were 107 QF requests highlights the concerns that the Company had and partially why it made its application.
Q. But there were more ...
A. Maybe I can --
Q. Well --
A. -- help you out. So, 107 was just a snapshot in time. They come and go over time.
Q. Correct.
A. You know, for example, when we made the filing in this docket, there were 3700 megawatts of requests. After we made this filing, that number grew to 42, 4300 megawatts of requests. Since then, it's dropped down to probably 2400 megawatts of requests. So, it moves around as projects come and go.
Q. Right. So, there's been more requests in the last two years where there's been -- in your testimony.
Didn't you testify that in the last two years there's been a dramatic increase in QF requests?

A. Yes. I can point you to that part of my testimony if that would be helpful. But yeah.

Q. That's fine.

A. It's actually on page ten of my testimony. In Utah alone, we've had 24 new QF projects totalling 897 megawatts that we have executed in the last two years. And again, that compares to the 2900 megawatts of average Utah load.

Q. So, the 24 contracts that you signed in the last two years is a considerably smaller amount than the 107 and more requests for contracts that you've negotiated?

A. That's correct. And again, that's a Utah number, where the 107 was a system-wide number.

Q. It's also true that assigning of a PPA is no guarantee that the project will be built.

Applications can be withdrawn, in some cases canceled; isn't that true?

A. Yes. That occurs.

Q. Of the 24 new contracts that were signed in Utah, have any of them been canceled or withdrawn or presently being disputed?

A. I believe we have one small project that is three megawatts or less that was terminated due to an interconnection issue. But I believe that's the only one.

Q. That's the only one of the 24?

A. That's correct.

Q. All right. In preparing your testimony for this hearing, did you review the rebuttal testimony of Mr. Peterson from the Department of Utilities?

A. Yes, I did.

Q. Do you have a copy of his rebuttal testimony?

A. I believe I do, yes.

Q. Could you turn to page seven of that rebuttal testimony?

A. (Complying).

Q. On line 27, it states: "Developers are hoping to take advantage of the ITC" -- that's the investment tax credit, "will likely have need to sign the purchase agreements in place before the Commission is likely to issue a decision in this docket."

Is that a fair statement in your opinion?

A. Yes. I agree with that. The ITC in its current form. It may be extended or modified but it's set to be reduced at the end of 2016.

Q. That's right. And your testimony in the other -- on Tuesday was that the large increase is primarily attributable to -- so the project attempting to be executed on contract in time to allow to build them

by the end of 2006 in order to take advantage of expiring federal income tax credit; correct?

A. Yes, that's correct.

Q. Given the history that an overwhelming majority of QF contract requests do not result in signed PPAs, your testimony that a primary reason for dramatic increase in contract requests to take advantage of expiring federal tax credit and Mr. Peterson's testimony, the opportunity to take advantage of the tax credits is closing as we speak, isn't it extremely unlikely that a significant number of the 40 outstanding contract requests will result in projects being built?

A. Well, I'm not sure I can speculate on that. We had a similar situation kind of in 2010, '11, and '12 with wind projects where we had a production tax credit that was expiring.

And so, it seemed like the rush on wind QFs was over. And then here came a lot of solar QFs.

And so, it's difficult to speculate on how many QF requests we'll get in the near future as panel prices change, different financing vehicles come about.

Q. If it's too speculative to determine that there won't be that many contract requests in the future, isn't it too speculative to suggest that there will be?

A. No. And it's not about a specific number.

And this is where I struggled a bit in preparing my testimony and forming an opinion on this matter.

The issue of fixed-price risk obviously grows with more megawatts. So, if you have one or two contracts that come in with a 20-year contract term, while there is some fixed-price risk for customers, that fixed-price risk is not as significant as if you have 2,000 megawatts of QF contracts that come in.

And I look at that as, you know, similar to diversification of a stock portfolio or a retirement portfolio. You may think natural gas stocks are quite low today, which many of them are, and you would say, I'm going to add some of those to my retirement portfolio. And you would add them in a percentage that is appropriate for your allocation.

You would not necessarily move your entire portfolio to natural gas stocks.

Now, what's challenging is, I don't know what the appropriate allocation is for QF contracts. Like I said, one or two QF contracts, you know, a hundred megawatts, perhaps, at a 20-year contract term, that fixed-price risk is much smaller than a thousand megawatts. So, there is some degree of variability depending on the size or the amount of QF contracts that come through the door.

Q. So, as you sit here today, you cannot speculate to how many of the 40 outstanding contracts that are presently being negotiated will be built?

A. Without knowing what the outcome of the ITC would be, no. I would acknowledge that over the past two years, we've signed contracts in the $60 range and we thought that was the lowest it could go, and a lot of our developers said that's as low as it could go.

And then we signed some in the $50 range and had that same discussion. And then we signed a few in the $40 range. And so, every time I think that we've hit the end, we move forward.

Q. I want to turn now to your testimony regarding the ratepayer indifference standard. In several places in your written testimony, you argue that the 20-year contract term violates the ratepayer indifference standard. And in your summary today, you've also made that argument; isn't that true?

A. That's correct.

Q. On page nine and ten of your direct testimony, you make the argument that a 20-year fixed-price contract can be considered a subsidy to the QF in violation of the ratepayer indifference standard.

Am I reading your testimony correct?

A. That is correct.

Q. But at no point do you attempt to quantify or monetize the amount of the subsidy; do you?

A. No.

Q. Isn't it true for the last several years the Company, the Division, and the Office have been arguing for the Commission that an unquantifiable policy consideration should not be taken into account in avoided cost pricing cases involving the ratepayer indifference standard?

A. Yes. When we're assigning costs and benefits. And this would be considered a benefit in my opinion. And if a QF is going to enjoy the benefit of a 20-year contract term, arguably, they should get a reduction in their price because of that but I don't know how to quantify that.

Q. Well, the Company has taken the position in the past few years that unquantifiable policy considerations should not be taken into consideration in avoided cost pricing cases involving the ratepayer indifference standards; isn't that true?

A. Yeah, that's correct. And I believe this is a benefit that cannot be quantified. So, it should not be allowed.

Q. Can you identify any case from the Public Service Commission or the Federal Energy Regulatory

Commission that apply to the ratepayer indifference standard outside the context of avoided cost pricing?

A. I might need you to rephrase that or unpack it a little bit.

Q. All right. I'm looking here at two quasi-judicial bodies, the Utah Public Service Commission and the Federal Energy Regulatory Commission. Do you understand that?

A. Yeah.

Q. Those are the only two issues?

A. Judicial bodies.

Q. Right.

A. Not quasi.

Q. Can you in your experience point to any decision or case or regulation from those two bodies where the ratepayer indifference standard was applied outside the context of specifically setting avoided cost pricing?

A. Certainly. We've had -- first of all, there's been other jurisdictions in which the Company operates such as Idaho where the contract --

MR. MOORE: I'm going to object. That's nonresponsive. I specifically asked about the Utah Public Service Commission and Federal Regulatory Commission.

MS. HOGLE: Mr. Clements, before you respond, can I ask counsel to please allow the witness to finish his testimony before he cuts him off?

THE HEARING OFFICER: Thank you.

And with respect to the objection, I think if Mr. Clements wants to discuss Idaho a bit before he answers the question, I think that's reasonable, and I'll allow him to do that to an extent.

THE WITNESS: Yeah, because the Idaho is relevant to FERC. So, I was getting to that point.

So, in Idaho, there were multiple rulings where there were issues other than the contract price. One of those was contract term. Some credit terms were also at issue, and parties even took the Idaho Commission to the FERC and the FERC said that the state Commission can opine and determine those particular things.

In Utah in particular, we've had multiple dockets that have addressed non-pricing issues, things like credit terms, performance guarantees and other contract terms that are significant but are not associated with the price.

And so, it's my position and I think the case law supports this, that the Commission has the ability to implement the ratepayer indifference standard across everything from price to contract terms to contract term meaning duration.

BY MR. MOORE:

Q. In your prefiled testimony, you've cited several cases, dockets both from this jurisdiction and other jurisdictions, statutes, federal and state.

But I don't believe, and correct me if I'm wrong, you cited to any case or precedent that applied the ratepayer indifference standard outside the context of the avoided cost pricing.

Could you correct me if I'm wrong?

A. Without performing a thorough review of each of those, many of those cases had issues beyond just the price. So, I'm not sure I would agree with that generalization.

Q. Well, you prepared -- you made the argument in your prefiled testimony, did you not, the ratepayer indifference standard applies and you made the argument here to terms outside the avoided cost pricing?

A. Yes.

Q. But you cannot cite to any case specifically now with your testimony in front of you that stands for that proposition. You can only say generally that some of these cases might make it?

A. Well, in general, I would refer to the two significant portions which would be Section 210 of PURPA and Section 292 of the federal regulations which encompass all of PURPA. I mean, we can take the time if you want to go through each of those.

But it speaks specifically to the ratepayer indifference standard or to the fact that the -- and I'll quote from one of them if it would help. "The incremental cost to an electric utility" --

"The incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

And that's how they define avoided cost in 18 C.F.R. 292-101(b)(6).

Q. That's exactly my point.

That's dealing specifically with avoided costing pricing; isn't that correct?

A. No. It doesn't specifically say avoided cost pricing. There's more that encompass avoided cost than just the price. I would refer you to the order in 03-035-14 or 12-035-100. Those are two orders from this particular Commission that addressed many issues besides just the price.

Q. Avoided cost are a corollary of the federal statute's incremental cost. Would you agree with that?

A. I would say "avoided" and "incremental" would be similar, yes.

Q. Would they refer to the same thing?

A. In practice, yes.

Q. And isn't the ratepayer indifference standard also a corollary to avoided cost?

A. Yes.

Q. And isn't that the only place that the ratepayer indifference standards exist in cases from the Utah Public Service Commission and the Federal Regulatory Commission?

MS. HOGLE: Objection. I believe that question has been asked and answered several times.

THE WITNESS: Yeah. Oh. Sorry.

THE HEARING OFFICER: I tend to agree that it has been.

MR. MOORE: We have no further questions.

THE HEARING OFFICER: Thank you. Ms. Dutton?

CROSS-EXAMINATION

BY MS. DUTTON:

Q. Thank you. Mr. Clements, do QF sources provide a capacity value?

A. Yes. The capacity value was determined in those two dockets I just referenced. So, that would be 03-035-14 and 12-035-100 the Commission determined the capacity payment for QFs.

Q. And do commodity hedges provide the utility with a capacity value?

A. Yes. Certain commodity hedges would.

Q. Could you explain that?

A. Certainly. When you purchase firm energy, it comes with liquidated damages. And so, firm market purchases do have some capacity value.

Q. Do you account for that in your IRP?

A. Yes. I believe some market purchases are in the IRP.

Q. Are the ratepayer indifference standard and the must-purchase obligation of PURPA applicable to QF resources?

A. Yes. That's the very basis of PURPA.

Q. And is PURPA applicable to the commodity hedges?

A. No. PURPA has no bearing on commodity hedges.

Q. Okay. Is it possible that at some point the avoided cost price will be so low that it will be uneconomical to build QF projects?

A. Again, I couldn't speculate on that because every time I've tried to do that, I've been wrong. So, I'm not going to guess on that one again.

Q. And did existing QF contracts contribute to the

decision in the recent IRP to push the next company resource acquisition out to 2028?

A. I'm not entirely certain. They probably did play a small role in that. The capacity contribution of wind and solar which is the majority of the QFs that we have received is not a hundred percent. And so, they may have contributed to that but I'm not certain.

MS. DUTTON: Thank you. No further questions.

THE HEARING OFFICER: Thank you. Mr. Ritchie?

CROSS-EXAMINATION

BY MR. RITCHIE:

Q. Thank you, commissioners. Travis Ritchie with the Sierra Club. Good morning Mr. Clements.

How are you?

A. Good morning.

Q. Mr. Clements, I'd like to start with a point that you made in your summary and you also addressed in your testimony. If I could turn you to page three of your rebuttal testimony, please.

A. (Complying).

Q. And starting on line 46 after the semi colon there, you state:

"A company resource can be dispatched and backed down when more economical alternatives are available passing through to customers the savings

from lower fuel and other operating costs because
the total cost of energy is not locked in for
20 years like it is in a QF contract."
Did I read that correctly?
A. That's correct.
Q. And is that the same point you were making in your summary about distinguishing a company resource from a QF contract?
A. That's one of the things that distinguishes it.
Q. And if I could also turn you to page twelve of your rebuttal testimony, please, and directing you to lines 246, you say:
"For example, if the marginal cost of a company
gas plant is $40 per megawatt hour but another
alternative such as a short-term firm market
purchase costs only $30 per megawatt hour,
the Company would dispatch down the gas plant
and buy from the market saving customers
$10 per megawatt hour."
Did I read that correctly?
A. Yes.
Q. And does this example that you describe on page twelve follow on the same point that I just read on page three?
A. Yes, generally.

Q. Now, in this example here on page 12, you say that the Company could back down the gas plant when the marginal cost of the plant is higher than other alternatives. And you specifically said marginal for a reason; right?

A. Absolutely, yes.

Q. So, for a company-owned resource like a gas plant or a coal plant, are there costs that ratepayers are responsible for covering other than the marginal costs?

A. Yes.

Q. And so, if you back down a plant -- Well, let me back up a little bit.

What are those costs that ratepayers would be responsible for other than marginal costs?

A. Well, you primarily have capacity and energy costs. I mean, if you want to go line by line, we can do that. But with any generating resource, you typically have a capacity cost and an energy cost. And the energy cost would be your marginal cost which would include fuel, variable O and M, chemicals, things of that nature.

And the point I was making here is with a company resource, yes, you're capacity costs are fixed and sunk if you want to call it that, but your marginal costs or your energy costs could be dispatched in such a manner that they are economic.

So, if there's another area where you can get a cheaper marginal cost, you can dispatch down your unit and acquire that. With a QF contract, when we calculate the capacity and the energy cost, we lock that in for 20 years, and the QF sells to us over the course of the 20 years at that price.

And we don't have the ability to go to the QF and say, we'll keep paying you the capacity but we've got a cheaper energy alternative, so back down. We don't have the ability to do that, and that was the point I was making then.

Q. And so, the ability that you have is that customers see savings from reduced fuel and operating costs; correct?

A. That's correct, yes.

Q. So, are you aware of any company-owned resources that currently have operating long-term fuel supply agreements that include minimum take privileges?

A. I'm not aware of any but I'm not aware of all of our long-term fuel agreements. So, I wouldn't ...

Q. Were you familiar with the closure of the Deer Creek Mine recently and the replacement coal supply agreement?

A. I'm aware of it but not the details of the coal

agreement.
Q. Would it surprise you to hear that the company entered into a 15-year coal supply agreement?
A. No, it wouldn't surprise me. Coal agreements are typically somewhat long term in nature.
Q. And based on your experience in the industry, do fuel supply agreements often have minimum tank provisions as well?
A. Gas do not, no. Coal often does, yes.
Q. And so, for a fuel provision like that, just understanding how a minimum take provision works, if you back down a plant, you still have to pay for some of that fuel even if you don't use it; is that correct?
A. Again, it depends what your minimum tank provisions are and if they require you to run a certain capacity level. I'd have to look at the exact contract on that.
Q. Fair enough. I'll move on from that.
A. Sure.
Q. So, I'd like to talk now about the kind of other category of costs for a company-owned resource that customers are on the hook for paying regardless of whether the plant has backed down.
Isn't it true that ratepayers still have to pay for the capital expenses at generating plants even if

those plants are backed down?

A. Yes, that's correct.

Q. So, when the Company is making a decision to justify whether or not a capital expense and a generating resource is prudent, the Company relies on the best estimates it has available for things like forward-looking fuel and power price forecasts to show that the capital expenditures are the least-cost, least-risk for the customer; is that correct?

A. Yes. And without rehashing that entire IRP process again, that's typically done within the two- to four-year action plan in the IRP and through that competitive bid process I discussed earlier in my summary.

Q. And now, if you have, let's say, a major capital addition at an existing generating resource.

Does that go through a competitive bid process like an RFP process comparing it to other generating resources?

A. The IRP accounts for those major capital improvements, and we'd have to talk about which ones you're referring to exactly.

Q. Okay. I'll take an example.

Are you familiar with the proceeding that occurred here a couple years ago discussing major capital

expenses at the Jim Bridger coal plant?

A. No. That's one I was not a part of.

Q. Are you aware of any of the proceedings that the Company has pursued to get pre-approval for major capital expenses at its generating facility?

A. Yes.

Q. And with regard to a large capital expenditure at an existing facility, isn't it true that utilities actions are generally judged based on the information available to the company at the time that it made the decision to spend the money?

A. Yes, after careful stakeholder review. And that's a critical point that I've made and I feel is very relevant here.

All of these major plant additions that you've been talking about go through a rigorous review process. And, in fact, some of these that you have discussed actually came before the various commissions that we have. The Company was required to justify their need. The Company was required to justify the expense and a lot of times got pre-approval before making that expense.

So, we went through a litigious process or at least an evidentiary hearing before making those expenditures. And my point in my testimony is, that's very different than what occurs with a QF contract where we may sign a $200 million nominal-value transaction that gets very little commission oversight or review. We're forced to execute that agreement.

Q. I believe you gave the example during your summary that QFs effectively require the Company to lock in the price of gas for 20 years because the avoided cost of that QF is based off of the then current price forecast; isn't that correct?

A. That's correct.

Q. But isn't it true that that same concept applies in those proceedings that you were talking about about capital expenditures where the Company comes forward to makes its case based on the long-term forward-looking price forecast available to the Company at the time that the decision is made?

A. That is correct with a major difference being need and the needs assessment. If you look at the 2028 resource, we're not going to go out and acquire that resource today because it's outside the IRP action plan.

And that was the point I was trying to make is with the QF contract, we don't go through that rigorous review process to make sure we have the need.

When we acquire these major plant additions, when we build a new power plant, it's because a need has been identified in the IRP, and that need shows up in that two- to four-year action plan. And at that point in time, we go out and acquire that resource. And that's different again than the QF resource.

Q. So, setting aside the Company's determination of its need for a minute, from the perspective of a utility scales, let's take a solar QF project, if you were in the shoes of that developer, isn't it true that the decision to spend the capital on the project has to be made up front?

A. Absolutely.

Q. And when the QF developer is considering whether or not to build a project, they have to look at the utilities current avoided costs to determine whether or not their project pencils out at a given price; is that correct?

A. That's correct.

Q. So, isn't it also correct that similar to a utility's decision to deploy capital, the QF developer should be provided with the same certainty that their cost calculations will not be second guessed if price forecasts and avoided cost calculations change three years down the line?

A. And again, the difference there is the Company only acquires those long-term resources when that need is identified in the IRP. And I know you said you want to set aside the need issue but the need issue is the crux of the argument here and the need issue is why it is, in my opinion, a violation of the ratepayer indifference standard.

Q. So, I'd like to turn you to page five of your rebuttal testimony right now, please, and on line 108.

Now, you state there -- are you there?

A. Yes. Go ahead.

Q. "Limiting the term of the contract to three years simply means that the price Rocky Mountain Power and its customers will be required to pay to the QF will be subject to adjustment every three years and will be more closely aligned with the Company's current avoided costs."

Is that correct?

A. That's correct.

Q. For the capital expense projects that we were talking about before where the Company has sought pre-approval for major capital expenses, would the Company accept a requirement to come back to the Commission every three years to prove that the capital expenditures were still the least-cost, least-risk option under updated power and fuel price forecasts?

A. Again, it depends on what capital costs you're referring to. The Company does have to come in and offer evidence of prudence on any expense it makes.

Q. But isn't it true that the Company, the original decision to deploy that capital is made based off of the best information available to the Company at the time that it made the decision to deploy the capital?

A. Yeah, that's correct.

Q. And so, would it be fair to ask the Company to come back in? Let's say if a decision to deploy capital was made in 2010 and price forecasts have changed since then.

Would it be fair to bring the Company back in today and say, you know what, if we rerun the numbers from the case that you presented in 2010, would these new numbers today -- that decision was wrong and it turns out that was not the least-cost least-risk decision. Would that be a fair thing to impose on the Company?

A. Well, from a capital standpoint, that doesn't occur. From an energy or marginal-cost standpoint, that does occur. The Company comes in in rate cases and energy balancing account proceedings and all its marginal costs, natural gas, chemicals, variable O and M are subject to review at that point in time.

And again, that's the difference between a QF contract and these company resources where the Company does lock in the capital piece through the lowest-cost least-risk needs assessment in the IRP.

And then the marginal costs are subject to change over the life of that asset. That's not the case for the QF contract. The capacity and the marginal costs are locked in from day one.

Q. But from the perspective of the QF as I think we just discussed a little bit more, the QF is making a decision of whether or not to pull the capital based on the then current avoided costs of the Company which dictates that pricing; isn't that correct?

A. Well, it's hard to speculate what they base their decision on. Some do not. I mean, that seems to be very unique to renewable QFs who require third-party financing to build the projects.

All of our combined heat and power projects, so, these are entities that have generation behind their meter like Tessoro, U.S. Magnesium, Kennecott, those entities typically elect to one- to two-year contract terms. And so, I don't know what they're basing their analysis on, but they're not looking at a long-term avoided cost as a justification for their project.

Q. Isn't it true that a lot of those facilities with cogeneration products, producing energy is not their core business; correct?

A. No. It wouldn't be their core business and that's the very reason why they -- and this is a very good point you bring up. That's why they don't enter into these long-term fixed-price sales to the Company.

It's for the same reason the Company doesn't want to enter into the long-term fixed-price purchases. Those entities say, I have too much fixed-price risk. I'm not agreeing to sell to you for 20 years at a fixed price. I'm only agreeing to sell to you for one or two years. They are on the other end of that fixed-price risk.

MR. RITCHIE: Thank you, Mr. Clements. I have no more questions.

THE HEARING OFFICER: Mr. Dodge?

CROSS-EXAMINATION

BY MR. DODGE:

Q.   Thank you, Mr. Chairman.

Good morning, Mr. Clements.

A.   Good morning.

Q.   You've made pretty clear your legal or other opinion that reducing the contract term to three years doesn't violate PURPA.

You haven't cited any FERC cases that say that; have you? You said the opposite but you found no FERC cases or regulations that say you have to offer long term. You've also offered nothing that says it is in

conformity with PURPA to restrict a PPA to three years; have you?

A. I have said that it is consistent with the ratepayer indifference standard which is really at the heart of PURPA. And I can say that --

Q. Please answer my question which is:

Have you cited any case law or regulations that say it is consistent with PURPA to offer a three-year PPA to maximum?

A. Yes. Again, I'd refer to the sections that I referred to earlier when the Office was providing their cross-examination.

Q. So, turn to that and show me where it talks about the length of the PPA.

A. It does not specifically talk about the length of the PPA but it does talk about avoided cost leading the ratepayer or customer in --

Q. I understand that. If you'll listen to the question, we'll get through this a lot faster.

I said, have you cited any regulation or case from PURPA or FERC or this Commission that says a three-year term is consistent with PURPA?

The answer to that is no; is it not?

A. No. That's correct.

Q. Okay. That's all I wanted. It's clear that

your company dislikes the must-buy obligation of PURPA.
That's a fair statement; isn't it?
A. That's not a fair statement.
Q. One of the executives of Berkshire Hathaway appeared before congress and asked that it be removed; did he not?
MS. HOGLE: Objection. Outside the scope.
MR. DODGE: I don't think it's outside the scope. If the Company's trying to eliminate the must-purchase obligation and he's sitting here saying that isn't their intent, I think it shows an inconsistency.
THE HEARING OFFICER: I think I'm going to rule that it's within the scope based on the previous answer Mr. Clements gave to answer within his knowledge.
THE WITNESS: Yes. And without getting into the details because I'm not knowledgeable of some of those that are current at the federal level, yes, there has been some work done there.
In fact, I was just reading this morning a letter from Republican leadership to the FERC chairman requesting they convene a technical conference to review the applicability of PURPA now. So, I believe there are some efforts going on at the federal level. I was responding from a personal level.

BY MR. DODGE:

Q. No. I asked you, is it not true that Berkshire Hathaway has taken the position that the must-purchase obligation should be eliminated from PURPA?

A. I believe they have taken that position.

Q. Today at least that hasn't happened; has it?

A. It has not.

MR. DODGE: May I approach?

THE HEARING OFFICER: Yes.

BY MR. DODGE:

Q. Mr. Clements, I'm going to hand you -- I notice in your testimony in all three rounds, although you provide extensive opinions on what PURPA requires and your interpretation of what PURPA is, et cetera, you don't once reference the Utah section that deals directly with PURPA. Is that a fair statement?

A. I don't believe I did reference it, no.

Q. Do you think it's relevant, should be relevant to this Commission what Utah law mandates on this issue?

A. Sure.

Q. Let's look at that. Before you I have an excerpt from Utah Code Annotated Section 54-12-1. The bold in there is mine. It's not in the statute.

Am I reading it correctly midway down at subparagraph one:

"It is desirable and necessary to encourage independent energy producers to competitively develop sources of electric energy not otherwise available to Utah businesses," et cetera, "and to remove unnecessary barriers to energy transactions involving independent energy producers and electrical corporations."

Did I read that correctly?

A. Yes.

Q. It goes on in subparagraph two:

"It is the policy of this state to encourage the development of independent and qualifying power production and cogeneration facilities ..."

Now, it's a fair statement, is it not, that nowhere in the Company's presentation to this Commission in its testimony was any effort made to demonstrate or even claim that reducing the PPA to three years is consistent with this Utah statute?

A. No. I did not reference this statute.

Q. You don't take the position, Mr. Clements, do you, that a three-year PPA will allow companies to continue to develop renewable energy, QFs, like the ones that you have signed in the last two years.

You don't take the position that will continue; do you?

A. Based on my experience, some may be able to purchase it. Some may be able to continue to build projects depending on what their financing options are.

Q. And that experience wouldn't be with anyone who's done a large QF project and financed it with a short-term PPA; would it be?

It's based on your speculation?

A. No. There have been multiple projects -- oh. And you're speaking to renewable. There's one renewable project that I'm aware of that built and completed construction without a long-term PPA.

Q. And you're talking about one you referenced in a data request in Wyoming?

Is that the one you're talking about?

A. Yes.

Q. And it's 19 megawatts?

A. I believe it's actually 17 and a half.

Q. 17 and a half megawatts. And are you aware there was actually no financing involved in that, it was completely company -- it's on a greenfield site of an industrial customer; is it not?

A. Yeah. I'm sure the term wasn't free. I'm sure there was some financing. They didn't require third-party financing.

Q. Did you know that there was outside financing?

A. No. Like I said, obviously there was some financing. Whether it was outside or inside, I don't know.

Q. Well, when I say financing, I'm talking about going to the market to get it as opposed to using internal capital. Are you aware that there was no outside financing involved in that?

MS. HOGLE: Objection. I believe he's answered that question.

BY MR. DODGE:

Q. Did he say he was not aware? If so, I'd just like to know the answer. I didn't hear it.

A. I don't know. The money came from somewhere. And whether it was internal financing that then required external financing, I don't know, but the project was built with a shorter PPA.

Q. And in Wyoming, 20-year PPAs are now allowed; right?

A. Yes. They were allowed --

Q. So, for some reason, a five-year PPA was negotiated, built by a company potentially with no outside financing for reasons you may not even fully understand or be free to disclose; right?

A. Well, I know the reason. The reason was, they didn't like how low the price was and they didn't

want to be locked into that price for 20 years.
That's why they chose short term.

Q. So, that's the totality of your experience that says maybe some companies can continue to develop large renewable projects with a short term?

MS. HOGLE: Objection. Argumentative.

BY MR. DODGE:

Q. Isn't the totality of your experience --

You said based on your experience you think maybe some can and you gave me one example. That's the totality of your experience with large renewable energy development projects being able potentially to be developed with terms of less than 20 years?

A. Correct. I would agree that it will become much more difficult for these entities to obtain financing based on my inexperience. I'm not denying that.

Q. Why don't you just admit it will stop it completely?

A. Because I don't know if it will stop it completely.

Q. But if it does, that's okay with you?

MS. HOGLE: Objection. Argumentative.

BY MR. DODGE:

Q. Is it okay with you? Is that the goal?

Are you trying to hit a pause button here and say, look, we don't like PURPA, let's pause?

A. Let me answer your first question. If you're asking me personally or me as representing the Company, I'll provide the same answer to you.

We are indifferent. The Company has never received a disallowance for a QF contract. When we sign these QF contracts, they go into net power costs and we get full recovery.

This proceeding will not impact the Company's earnings or the Company's bottom line in any way. This isn't about the Company versus QFs. This is about maintaining the ratepayer indifference standard.

And so, I'm not okay with it. I'm not okay with it. I'm ambivalent. I've sat in this particular chair, sometimes that one, sometimes arguing for QFs, sometimes arguing against QFs, but always trying to do what's fair.

So, I'm a bit agnostic to the point of whether they get built or not. And I don't mean that in a cold-hearted way. I just say, I try to administer PURPA in a fair manner for both the QF and the customer. That's what the Company's trying to do.

Q. And it's touching that you're looking out for the customers. You recognize the only two customer reps

in this room oppose your attempt to change the term.
You understand that; don't you?
A. I don't know which two customer reps --
Q. The Office is statutorily obligated to look out for the interests of residential and small business customers; right? UAE is a member of our coalition and it opposes it.
Is there any customer representative that you know of here supporting your approach?
A. No. They don't typically do that. Quite honestly, I was surprised at the Office's position. With some of the risks that they raised in their testimony, I was surprised at the position they took.
Q. Maybe they know how to read a statute and understand what Utah law requires in terms of encouraging the development of independent power production that perhaps you lack. Do you think that --
MS. HOGLE: Objection. Argumentative.
THE HEARING OFFICER: I'll sustain that objection.
MR. DODGE: Mr. Clements --
May I approach again, Mr. Chairman?
THE HEARING OFFICER: Yes.
(RMCRE Cross Exhibit-1 identified)
BY MR. DODGE:

Q. Mr. Clements, you also I think fail in your testimony to spend any time with the most recent Utah Public Service Commission ruling on the issue of the term of PPAs. You referenced it this morning in a different context but I'm going to hand you -- and I haven't marked this or the last one, Mr. Chairman, because you can clearly take administrative notice of it. I don't feel the need to get it introduced into the record, although I'm happy to if it would it be useful.

I'll represent that this is an excerpt from the Commission's order in Docket 03-035-14.

You referenced that this morning, although in your testimony I think, if at all, it was in response to others. You didn't go into a discussion of what the Commission and even the Company decided in this 03 docket. And it's the last time the Commission ever looked at the length of QF PPAs; is it not?

A. I believe that was the last time, yeah.

Q. If you look at on page 28 of this, it says, "CONTRACT ISSUES, Contract Term." Right?

And it starts with, "PacifiCorp testifies" -- and I'll skip down a little bit:

"... the 20-year term represents an appropriate balance between a term that allows the QF to secure financing and limiting the risks that accompany

long range price forecasting ..."

Did I read that correctly?

A. That's correct.

Q. And if you turn to page 29 at the bottom of that section before the section that begins, "Levelization," the Commission order says:

"We find reasonable and accept the parties' common position providing for a standard term limit of 20 years for QF contracts with the allowance for parties to petition the Commission for longer terms."

So, the Commission was even willing to accept potentially longer terms under circumstances if someone could demonstrate the appropriateness of it; right?

A. That's correct.

Q. So, if that was a governing concern the last time this Commission looked at it, don't you think the ability of QF developers to obtain financing is still a relevant consideration?

A. Well, I don't see in the order where they specifically said that they were making that finding based on the need to obtain financing.

Q. Were you in that docket?

A. Yes, I was at the tail end.

Q. And do you recall there was testimony from UAE

among others saying you need a long-term contract in order for it to be financeable, we support QFs?

And that was the whole discussion in the settlement, was it not, does it have to be 30 years versus 35 years versus 20 to be financeable. Was that not the whole issue in that part of the docket?

MS. HOGLE: Mr. Clements, if you cannot remember, you don't have to answer that. That's ten years ago or longer.

THE HEARING OFFICER: Is that an objection?

MS. HOGLE: Objection. Yes.

BY MR. DODGE:

Q. Well, let's see if he does remember.

Do you remember?

A. Well, I wouldn't -- you would probably need to talk about what occurred during the settlement meeting which I think is how you phrased that. This was the issue during settlement.

Q. No. In the testimony I said. Did we not file testimony to that effect, the parties not?

A. I believe you did, yes.

Q. And the parties ultimately settled on 20 with the option to extend it to 35 with a filing with the Commission in large part as the Company testified to try and balance the long-term price risk against the need

of QF developers to have access to financing.

And my question is, is that not still a relevant consideration if it was in the Company's own testimony in the 03 docket?

A. The Company's testimony did not speak to financing in that particular docket. And the Company's testimony in support of the 20-year term at that point in time was a compromise to other parties' desire for a 35-year contract term.

And again, as I mentioned in my testimony, and that's what you're failing to recognize or acknowledge, that things have changed since this original docket kicked off in 2003.

Q. I understand that and I'm going to cut you off and ask the chairman's permission to do so. I know you want to give a speech. I'm just going at, is it not still a relevant consideration?

We know your testimony that you believe circumstances have changed. I'm not asking about that.

Is it not still a relevant consideration?

A. Do you mean --

Q. The ability --

A. -- whether it can be financed --

Q. -- to obtain --

A. -- or not?

Q. -- financing for QF projects in order to encourage the development of such projects.

A. Again, that was your testimony at that point in time that it was relevant. I don't see in the Commission order where the Commission determined that was relevant and it wasn't the Company's position at that time that being able to finance a project is relevant. And again, it's not the Company's position at this point in time that being able to finance is relevant.

Q. Let me read from the -- and I guess I will ask that this be marked because maybe we need to have it in the record, we know what we're referencing. So, I'll ask that this be marked as Coalition Cross Exhibit-1?

THE HEARING OFFICER: If any party objects to that, please indicate. Not seeing any, it will be marked.

(RMCRE Cross Exhibit-1 marked)

BY MR. DODGE:

Q. I'm going to read once again, Mr. Clements:

"PacifiCorp testifies, contracts for the required purchase of power from QFs should be limited to a term of 20 years ..."

It says:

"... the longer the term, the greater the risk to the Company and ratepayers of incurring an

uneconomic power purchase agreement; semi colon the 20-year term represents an appropriate balance between a term that allows the QF to secure financing and limiting the risk that accompany long range power price forecasting ..."

That is a reference to the Company's position in that docket. So, the Company did take a position in that one, did it not, that balancing those two issues, long-term risk and the ability to obtain financing was an appropriate consideration?

MS. HOGLE: Objection. Asked and answered.

BY MR. DODGE:

Q. Well, he answered it wrong. I think I'm allowed to explore. He said the Company didn't take a position. And I just read you that I believe they did take a position; did they not?

A. Yes. And the position was taken -- oh.

THE HEARING OFFICER: Well, yeah. I think I'll allow one more brief answer from Mr. Clements but then ask the cross-examination to move on.

BY MR. DODGE:

Q. Okay.

A. Yeah. At that point in time, the Company was assessing a 35-year contract term and determined that 20 years was appropriate or something it could support at that point in time.

Q. Mr. Clements, you discuss in great detail ratepayer risk. And again, it's touching that you care about it. Ratepayers have a risk of variable price options, too; do they not?

A. You'll have to expand on that question.

Q. Is there no risk when ratepayers are left open to variable price or market price options as opposed to fixed price?

A. Yes. There is some risk. That's why you hedge to avoid that risk.

Q. Well, that's one way you hedge. Another way you hedge that is you build resources when you determine that that's the most cost-effective option; right?

A. That's correct.

Q. Another way that the Company has done for many many years is enter into long-term PPAs; has it not?

A. Historically, yes. Over the past ten-plus years it has not.

Q. It still has some long-term power purchase agreements; does it not?

A. I believe it does have a small amount. The Company is prohibited by policy implemented as a result of the hedging collaborative from doing that today.

MR. DODGE: We'll get to that. That's not a true statement, but we will get to that in a minute.

MS. HOGLE: Mr. Dodge, objection.

Can you please let Mr. Clements finish his testimony before you cut him off?

MR. DODGE: Is that a request or are you asking the Commission to rule --

MS. HOGLE: I'm asking you on a professional level to please let my witness answer the question before you cut him off.

THE HEARING OFFICER: And I think we're on Mr. Clements' answer right now.

THE WITNESS: I think I may have been done.

BY MR. DODGE:

Q. I think you were probably done. The risk, the fixed-price risk, meaning once you've tied into an agreement, a contract, you no longer have the right to go try and get market resources if they're lower. You no longer have the risk of higher prices; right?

That same risk is faced with any long-term company resource; correct?

A. Any long-term fixed-price contract or obligation carries that risk, yes.

Q. And so, you, for example, try and illustrate the prices of some PPAs entered into a few years ago

in the last few years to what the current strip is.
First of all, the strip isn't guaranteed.
That's a projection; right?
A. That's correct.
Q. You can't go buy that ten-year strip today for that price?
A. You potentially could.
Q. An electric strip?
A. Possibly.
Q. Possibly?
A. Yes.
Q. Not many customers are out there taking the other side of that risk; are they?
A. That was my exact point earlier, that long-term electricity contracts are not entered into anymore.
Q. But you could make the similar analogy. You use numbers in the range of 60 some-odd dollars for the QFs and 40 some-odd dollars for this strip that isn't tied down. What was the comparable cost of the last resource the Company built?
Let's go to the Lakeside two project.
If you looked at the 2015 price per megawatt hour of that, would we not be in the $80 range?
A. I don't have information in front of me.
Q. Would that surprise you if it's in the $80

range?

A. 80 would surprise me, yes.

Q. What would not surprise you?

A. 40, 50. We'd have to look at that price but again, I don't speculate.

Q. You think all-in costs, including the fixed costs of the Lakeside two power plant in 2015 is $40 a megawatt hour?

A. Oh, including capital?

Q. I'm talking the all-in cost.

A. Again, I don't have those numbers in front of me. So, I couldn't speculate on that.

Q. $80 there wouldn't surprise you; would it?

A. Again, I don't have the numbers. So, I don't want to speculate on that.

Q. So, if you wanted to show ratepayer risk, you could say, well, that was a decision we made looking at the exact same metrics shows we're $40 out of the money on the other side with a Company resource; right?

A. Correct. And again, in my summary today, I said -- I agreed with that very very point, that it could just as easily be $1.2 billion in the money. It's not a matter of betting right or wrong. It's the fact that you're making a long-term bet that you otherwise would not.

Q. But you do make that bet in other contexts?

A. I would say it's not a bet in that context. And again, that gets back to the IRP. You have an identified need that's gone through a rigorous review process that goes through a request for proposal process. You get exactly what you want, how much you want at the time you want.

Q. I understand that's --

A. And that's something that's of a material difference.

Q. I understand that's your testimony. We'll talk about the IRP in just a moment.

You claim that the hedging policy now prohibits you from entering into long-term power purchase agreements; is that correct?

Is that your view of the hedging policy?

A. No. The hedging policy prohibits traders from doing that without stakeholder review. So, long-term contracts can be entered into but they require additional review.

Q. Mr. Clements, were you a member of that hedging collaborative?

A. No, I was not.

Q. I was. Would it surprise you or would it be inconsistent with your view that long-term PPAs for

electric power purchase agreements were never even discussed in that collaborative?

A. That would surprise me.

Q. Would it surprise you that in the Exhibit-A to that collaborative that shows the policy, the principles and the general guidelines adopted by the participants is never mentioned? Would that surprise you?

A. It would.

MR. DODGE: Let me hand you that exhibit.

May I approach, Mr. Chairman?

THE HEARING OFFICER: Yes.

(RMCRE Cross Exhibit-2 identified)

BY MR. DODGE:

Q. What I'm going to hand you is Exhibit-A. I chose not to copy the entire hedging report because it's somewhat voluminous, but I did copy the Exhibit-A which was the document that was negotiated I'll represent by the parties to that hedging collaborative and that formed the basis for the stipulation to the Commission to adopt these new hedging policies.

Is that consistent with your understanding of what went on in the hedging collaborative?

A. Again, I wasn't actively involved in it, no.

Q. So, I turn your attention and I'd invite you to read this. You weren't a participant in it and maybe you have a different view of it than I do, but review this as much as you want. I'll point out a few specific parts.

For example, in the paragraph one, it talks about PacifiCorp's expertise, blah, blah, blah. And at the end it talks about, "... related to natural gas procurement, energy balancing, and hedging."

First of all, would it surprise you to learn that this whole collaborative came about because of complaints about natural gas hedging, short-term financial natural gas hedges the Company was making out four and five years for more than a hundred percent of its natural gas needs?

A. I'm not sure about all those facts you just listed, but I know it came about because of the natural gas hedges.

Q. Let me turn your attention down to paragraph seven of that in the, "Principles."

"Voluntarily pre-approval procedures under Utah Code Section 54-17-402 may be used for long-term commitments that fall outside of the suggested guidelines."

Did I read that correctly?

A. Yeah.

Q. So, you accept that part of the hedging collaborative procedure was, if you're going to talk

long-term commitments --

Now, this doesn't say PPAs, but even if it included that, it contemplated that that would be dealt with outside of the hedging guidelines; did it not?

A. Yes. And I referenced that in my testimony.

Q. And then we go down to paragraph nine of "Principles."

"All commonly used, available and effective physical products and financial instruments may be utilized in Energy Planning and Procurement as appropriate."

It specifically contemplates continuing to use all commonly-available physical and financial products including a PPA; would it not?

A. It doesn't prohibit the use of a PPA, no.

Q. Well, in fact, it says they should continue to be used as appropriate; does it not?

A. Yes, "as appropriate" is pretty significant there.

Q. And then under "General Guidelines" -- but you're trying to claim that this hedging policy precludes you or is inconsistent with what you're doing.

And I'm saying, in here, show me where that inconsistency shows up in the Exhibit-A that the parties agreed to in that hedging collaborative.

A. Well, in, "General Guidelines" number one at the bottom of page 14:

"The forecast total requirement for natural gas and electricity should not be fully hedged."

Q. "Fully hedged" because the Company was 100 percent, more than 100 percent hedging its natural gas requirements at the time. "Fully hedged." No one here is talking about fully hedging anything; are we?

A. Well, I don't know if you were testifying to that. I mean --

Q. Are you?

A. You're speaking to things that occurred during the negotiation of this document.

Q. No. I'm reading what's in the exhibit that went before the Commission.

A. Yes. And it says:

"The forecast total requirement for natural gas and electricity should not be fully hedged."

Q. "Fully hedged."

A. Yes. And the point I made earlier -- and that was my exact point and my exact concern with the PURPA obligation. There's nothing stopping us. We can have 10,000 megawatts of QFs come through the door and we would have to execute each one of those contracts.

Q. Let's get back to the Exhibit-A. The next

sentence illustrates what the first sentence is talking about: "A reasonable percentage of the natural gas
requirements should remain open to short-term market
price exposure and allow for operational
flexibility. The percentage of natural gas
requirement .... is as follows:"

Now, that's blacked out because that's a confidential part of this document.

That's talking about fully hedging natural gas and keeping some of it open; correct?

A. That's correct.

Q. It goes on in paragraph two that:

"PacifiCorp should use Fundamental and
technical analyses with consideration of the
Company's risk management metrics, to determine
timing and volume of electricity hedges."

There we're talking about financial hedges; are we not?

A. I don't read it that way.

Q. You weren't in the collaborative; were you?

A. No. As I read the plain language of that, it says: "... Fundamental and technical analyses with
consideration of the Company's risk management
metrics to determine the timing and volume of
electricity hedges."

Q. And "hedges" as described in this document is talking about the financial instruments the Company was using to hedge natural gas and electricity purchases.

A. And I don't see a material difference between a financial hedge and a physical hedge when it comes to fixed-price risk. The only difference is deliverability.

Q. I understand that's your view. My point is, you're trying to claim this document somehow requires the position you're talking here in this case.

And I'm trying to find out where in this document it does it because I was part of that collaborative and I completely disagree. So --

MS. HOGLE: Objection. Assumes facts not in evidence.

MR. DODGE: I'll tell you what, I'll withdraw it.

THE HEARING OFFICER: Make sure we're not crossing the line of you providing testimony on what happened unless you're going to do that later.

BY MR. DODGE:

Q. Thank you, Mr. Chairman. I will do that. Paragraph five: "Proposals for long-term natural gas

supplies, transportation, storage and price hedges

should be solicited and evaluated as part of an

Energy Planning and Procurement process,

particularly in an environment of favorable Fundamentals."

Right? Now, that's natural gas, but I read that correctly; did I not?

A. That's correct.

Q. "The 36-month guideline for financial hedges," financial hedges, "and the suggested annual percentage guidelines should not limit opportunities for longer term hedges, supply commitments, or storage contracts in a price environment advantageous to natural gas consumers as determined by Fundamental analyses."

So again, that's natural gas. It contemplated longer term acquisition when financial conditions contemplated it; did it not?

A. Yes. And one of those actually occurred.

Q. My point comes back to, you tried to use this hedging collaborative -- I understand if you're saying, the principles as you read them of this hedging collaborative you were not involved in somehow supports your position. But it's not a fair statement; is it, Mr. Clements, to claim that this requires a shortening of the PPA term before this Commission?

MS. HOGLE: Objection. Asked and answered.

MR. DODGE: Well, if his answer was --

MS. HOGLE: Several times. Asked and answered.

THE WITNESS: I'll answer it.

THE HEARING OFFICER: I think there's a discreet part of the question that's unique that I'll allow an answer to.

THE WITNESS: I'd like to answer that because several times you've said what my opinion is. You've never let me actually say what my opinion is.

This document -- so, the hedging collaborative was around the fact, it got its basis around the fact that the Company put on some multi-year gas hedges that were in the money and then went out of the money.

And the parties were concerned about the fact that there were these long-term hedges that were put in place and the impact that had on customer rates.

The document, yes. The plain language of the document, one, applies to natural gas primarily; two, says, if you want to do something long term which is beyond 36 months, it needs to go through a fundamental analysis and a long-term review process.

Those principles are consistent with the Company's application in this matter where we are requesting that if a contract locks in a price for 20 years, it requires additional fundamental analysis and stakeholder review before being executed.

That is my position, that the fundamental principles behind the hedging collaborative say that if you're going to put on a long-term fixed-price bet, it needs additional review. That's my testimony.

BY MR. DODGE:

Q. And does the avoided cost pricing at which QF contracts are executed not get significant review before this Commission?

A. Again, the methodology does. The price itself does not.

Q. The price that comes out of the methodology; right?

A. Yes.

Q. The methodology determines the price and in light of changing information over time; correct?

A. That's correct.

MR. DODGE: Thank you.

THE HEARING OFFICER: Mr. Dodge, if I could just -- I think it might be a good time to take a short break unless you just have a little bit to do. But it seems like you have a couple more topics you're going to address.

MR. DODGE: A couple more. It won't be significantly longer but I'm happy to take a break.

THE HEARING OFFICER: Why don't we recess for ten minutes. Thank you.

(Recess taken from 10:36 a.m. to 10:47 a.m.)

THE HEARING OFFICER: Okay. It looks like we have all counsels present.

Mr. Clements, you're still under oath and we'll continue with Mr. Dodge's cross-examination.

MR. DODGE: Thank you, Mr. Chairman, for that break, and as a result of it, I'll be much shorter. I just have a couple more issues to address with Mr. Clements, but first I'd like to move the admission of Cross-Examination Exhibit-2, the hedging --

THE HEARING OFFICER: I'll ask any party to state their objection if they have one. I'm not hearing any. So, it'll be admitted. Thank you.

(Rmcre Cross Exhibit-2 Admitted)

BY MR. DODGE:

Q.   Mr. Clements, you discussed the IRP several times. I just want to ask you a few questions about your understanding of the IRP.

Is it a true statement that long-term QF PPAs at avoided cost prices are not among the resource options that the IRP chooses?

A.   Yes. That would not be a resource that it could select.

Q.   Long-term arrangements maybe but they're set

at cost and not at the utility's presumption of cost and not based on avoided cost pricing; correct?

A. Yes. Arguably, if the avoided cost reflects the IRP avoided cost for resource, then those should be the same in principle, yeah.

Q. Secondly, although you talked about the two- to four-year action plan and in your view, the inconsistency with 20-year PPAs with that, it is true, is it not, that the IRP process, A, uses a 20-year planning horizon and, B, based on that 20-year planning horizon results in decisions that may be a 40- or 50-year resource commitment?

A. Yes, that's correct. It tells you what you should do over the next 20 years.

However, it doesn't have you do anything until you get within two to four years of when you actually need that. But then when you do something, yes, it often results in a 40- to 50-year asset life.

Q. And then let's talk just a minute about what it says as the need. The 2015 IRP, does it not identify roughly a thousand megawatt, talking capacity now, need or shortage between projected resources and projected demands or loads throughout most of that 20-year planning horizon?

A. Yeah. I'm not sure I can confirm the thousand megawatt number. There are quite a few front-office transactions for the summer peak period.

Q. And so, the summer peak period, you get short -- these transactions are under a year in the IRP; correct? They assume contracts of under a year?

A. Yes. They assume you'll be able to go out and acquire those in one-year increments, yes.

Q. So, isn't it a fair statement that under your current IRP, there is a demonstrated need both for energy and capacity above the Company's committed resources in every of the 20 years but that the IRP has selected as the least-cost resource, for the most part, demand-side management and front-office market transactions, short-term less-than-a-year market transactions?

A. Yes. And the primary reason for that is it's selected primarily Q3 or summertime peak market purchases. So, that's when we have that deficiency and it says go out and get market purchases just for that time period. So, that's a very unique product.

Q. Had the cost benefit analysis that the Company engages in in the IRP said with that -- and I'm just using thousand as a round number. Maybe it's 800. Maybe it's 11 some years, but had it said, in order to meet that peek demand need -- and again, I'm talking demand as opposed to energy, we're going to build another

Lakeside three if there were such a creature in the works or something like that. If that had been the lower-cost assumption, damn the market resources, it would have picked that for now; correct?

A. Yes. It would have.

Q. And when you do avoided cost pricing, you look at what your long-term projected energy and, if it defers something down the road, demand savings will be and that gets incorporated into the avoided cost pricing; correct?

A. Yes. It looks at your long-term capacity need and a forecasted long-term energy need; that's correct.

Q. And today, when you send out indicative pricing today based on the current queue and your current assumptions in the grid model, you're down in the $30 per megawatt hour range; correct?

A. Sorry. I'll need you to repeat that or rephrase that.

Q. The most recent QF indicative pricing request that you personally have responded to, that's been within the last few months; correct?

A. Yes.

Q. And the indicative pricing, without getting specific, the levelized 20-year pricing is in the $30 per megawatt hour range; correct?

A. 30 to 40 depending on the project of course.

That's solar you're talking about. Other projects might be higher.

Q. I am talking solar. Thank you. And that represents primarily the displacement of front-office transactions over that 20-year planning horizon; correct?

A. Correct. It displaces some front-office transactions. Why the IRP didn't select a solar project instead of those front-office transactions is because you have to take the solar year round and not just during the summer on peak period.

And the reason I'm well versed in that is because I personally have looked at the front-office transactions and the IRP and I said, is there a way for us to build more renewables instead of having all these market purchases. And it's not economic to do so. So, that's why I'm fairly well versed in that one.

Q. And in those hours, the hours where you're taking the energy when you don't need the capacity --

You still need the energy; correct? It's not forcing you to take energy you can't use?

A. Well, you can always use the energy. It's just, what are you avoiding and what are your costs to do that.

Q. And in the current grid model when you do indicative pricing, primarily the energy that's being

displaced, the assumption of energy is the front-office transactions out through that 20-year term; correct? I'm talking --

A. Again, the front-office transactions cover those on-peak summer periods and not the entire year. And I will -- if I can have one correction to one of the things I agreed with you earlier.

There will be times in the future where there will be energy that we cannot use and there are quite a few studies that have talked about how there may be some hours with the proliferation of solar that's coming on, there may be some hours where you have some negative energy pricing but we don't see that now.

Q. And if that were forecast, that would reduce the avoided cost pricing. In other words, the pricing takes that into consideration; does it not?

A. Yes. The model does take that into account.

Q. And when you say you looked at a solar project, this would be a Company-sponsored project where all the costs go in. You take the energy, et cetera; right?

A. Yes.

Q. That's a utility model. But with a QF model where you're determining that long-term avoided-cost pricing, it takes into consideration that energy in the middle of the night in the shoulder months maybe almost

zero --

A. Absolutely.

Q. -- or very very low?

A. Yes.

Q. And that's all they're being paid for?

A. Yes.

Q. One last question. You comment that Mr. -- in your surrebuttal. You don't need to turn to it unless you'd like to and I'll give you the cite.

You commented in your view Mr. Harris and Mr. Isern who are Coalition witnesses, other than their own opinions, they haven't provided any evidence that the three-year term would stop all renewable development.

Is that a fair characterization of what you testified to?

A. Correct.

Q. It's on lines 42 to 46 of your surrebuttal.

A. Yeah, that's correct.

Q. A, asking Mr. Harris and Mr. Isern to provide evidence other than their own opinions that it would stop development is asking them to approve a negative; right? That it cannot be financed with a three-year term. They said in their opinions it can be.

You're saying, other than their opinions, they haven't provided evidence. That would be asking them

to prove a negative; would it not?
A. Yeah. It's difficult to prove a negative as we witnessed when you asked me to prove that PURPA doesn't say a three-year contract term. So, yes, it's very difficult to prove a negative.
Q. You understand, do you not, that Rocky Mountain has the burden of proof in this docket?
A. Yes.
Q. And you accept that part of that burden is to show that its proposal is consistent with all aspects of Utah law, not just the ratepayer indifference standard but also the policy to encourage the development of these resources. You accept that; do you not?
A. I do, yes.
MR. DODGE: Thank you. No further questions.
THE HEARING OFFICER: Thank you. Before I go to Mr. Sanger, to make sure we have the record clarified, I want to ask Mr. Dodge earlier in his cross-examination, were you making an appearance on behalf of UAE?
MR. DODGE: No. I don't remember, honestly, if UAE intervened separately. If so, then I guess I'm appearing for them as a member of the Coalition. And so, they're a member of the Coalition and they support the Coalition testimony.

THE HEARING OFFICER: Oh, okay. That clarifies it.

MR. DODGE: That was the point I meant to make, and I apologize if I said it in a different way.

THE HEARING OFFICER: Thank you. Mr. Sanger.

CROSS-EXAMINATION

BY MR. SANGER:

Q. Thank you. Good afternoon.

A. Good afternoon.

Q. Or actually, good morning.

A. Good morning.

Q. I won't be quite as much fire and brimstone as Mr. Dodge, but I'd like to move forward a little bit. I wanted to ask you a couple of questions on the testimony you gave a little bit earlier.

You said that the Company or that you are agnostic regarding the purchase of QF power; is that correct?

A. That's correct, yes.

Q. And is that the Company's view, that they're agnostic on the purchase of QF power as well?

A. Yes. We try to implement the Commission orders and make recommendations to the Commission that would leave us in that position.

Again, we're balancing customers and the ratepayer indifference standard and the rights that QFs have under PURPA and state law.

Q. And you get to recover all your costs of QF contracts and your power cost to adjustment mechanisms or rate cases or whatever; is that correct?

A. Well, we have the opportunity to recover all of our costs in some circumstances, a portion of our costs in other circumstances. And without elaborating on that too much, due to the sharing bands in the energy balancing account, there are some QF costs that go unrecovered. So, maybe we're not agnostic.

Q. So, that means that you've moved from the agnostic to the slightly opposed category?

A. No. I guess I should revise my earlier testimony where I said it doesn't impact our bottom line. But the energy balancing account is short term in nature, and so, most of those contracts would fall within that anyway. And so, our proposal would not affect the financial impact to the Company. And that's not our objective here.

Q. Okay. So, does the Company earn a return on its QF contracts?

A. It does not unless it owns it which the Company currently does not own a QF contract at the PacifiCorp level.

Q. Okay. And if the Company built a similar biomass or solar or wind or any other sort of QF project or any other renewable project, would the company earn a return on that investment?

A. Presumably, yes, if we had the opportunity to.

Q. So, if the Company builds its own resources rather than purchase QF power, there's a different impact on the Company?

A. From an earning standpoint, yes.

Q. So, is Berkshire Hathaway, they're not indifferent to whether the Company purchases QF power or builds its own power?

A. Again, at the Berkshire level, they may have a different opinion, but at the PacifiCorp level, we're simply trying to balance customer interests and rights of QFs.

Q. But the Company's shareholders aren't indifferent?

A. Well, PacifiCorp doesn't have any plans to develop QFs within its service territory to own and operate them.

Q. But you have plans at some point to own and operate renewable projects or at least nonrenewable projects at some point?

A. Well, they are in the Integrated Source Plan but when we go out and acquire those, it's through a request for proposal process and --

Q. Well, I know we've gone through the process. Right now I'm just trying to get to the point about whether your shareholders are indifferent to whether you purchase QF power or you build a resource yourself.

MS. HOGLE: Mr. Clements, I would advise you to only answer that question if you know for a fact that that's true or not.

THE WITNESS: Well, trying to finish my earlier answer, when we go out and acquire renewable resources, we do so through an RFP. And sometimes the Company does submit its own project, but the RFP selects the lowest-cost least-risk project. And in many of our wind RFPs, that turned out to be a power purchase agreement.

So, there's no -- in the Company's procurement process, there's no additional desire or credit given to a company project over a PPA.

BY MR. SANGER:

Q. But if the Company acquires a renewable project, then it can earn a return on that project if it builds it or purchase it for its own self?

A. Yes.

Q. And you said the Company always does an RFP for its wind purchases?

A. Typically, yes. I mean, there is statute in Utah and in Oregon that requires us to do so if the project's of a certain size.

Q. And has the Company always done that?

A. I would say that's the typical practice, yes. It's unusual for the Company to go out and acquire a project without that RFP. In the last several years, there were some times the Company built projects that were economically sensitive from a timing standpoint.

Q. And did the Company do that for its Rolling Hills project, did it have an RFP?

A. I believe that was one of those instances where it was an economic timely opportunity.

Q. And by "economic timely opportunity," are you aware that the Oregon Commission disallowed the Rolling Hills and rates because they concluded it was not economic?

A. I'm not certain of the exact reason. That's not my understanding.

Q. Did the Oregon Commission disallow Rolling Hills rates?

A. I'm not certain of the details around that. I believe they did on a portion of it.

Q. Okay. I'd like to move on to how Schedule 37 works. Can you just give a brief one-minute overview

of how Schedule 37 prices are set?

A. So, Schedule 37 prices are set in a similar manner to Schedule 38 where there is a production dispatch model run and there's an avoided capacity determination. The difference between Schedule 37 and Schedule 38 is Schedule 37, the calculation's performed once and prices are set in the tariff and there's a cap on the tariff at 25 cumulative megawatts for that tariff and then any QF contract can be entered into under that tariff at that pricing.

Q. And isn't there a difference between resource sufficiency and resource deficiency in Schedule 37?

A. I don't believe so.

Q. And how are capacity payments paid in Schedule 37?

A. They could be paid levelized over the term of the agreement or unlevelized.

Q. Does the time of the Company's next resource, thermal resource acquisition, have any impact on capacity payments?

A. The timing would, yes.

Q. So, how does that work?

A. I believe in 37 now, it's calculated in a similar manner to 38, but we've had so many 37 dockets recently, I'd have to check on that one.

Q. So, wasn't there a recent proceeding here at the Utah Public Service Commission where certain capacity payments were removed during the early years out of Schedule 37?

A. Yes. There's no longer a simple cycle capacity payment during the sufficiency period.

Q. Okay. So, what is the sufficiency period?

MS. HOGLE: Objection. I've allowed Mr. Sanger to ask these questions, but I think it's getting a little beyond the scope of the proceeding and Mr. Clements' knowledge with respect to that particular proceeding. And so, I'm wondering how much longer Mr. Sanger is going to question or go beyond this line of questioning.

THE HEARING OFFICER: Mr. Sanger, would you like to address the objection?

MR. SANGER: Yes. So, this is an issue that my witness John Lowe addressed, the resource efficiency/deficiency determination. I assume Mr. Clements read that testimony.

Did you, Mr. Clements?

A. Yes.

MR. SANGER: And his rebuttal testimony does not respond to Mr. Lowe on this point. So, I wanted to inquire. I'm laying the foundation for my questions. I wanted to inquire about how those prices are determined and how the three-year contract term impacts that determination.

THE HEARING OFFICER: Okay. And so, you know, I think we need to, as a general rule, limit cross-examination to issues that Mr. Clements addressed or doesn't address in his rebuttal or surrebuttal. I think there is some relevance of the manner in which Schedule 37 pricing is calculated, but that may be more appropriate to deal with with your witness if Mr. Clements did not address that in his testimony.

BY MR. SANGER:

Q. Okay. So, I will abbreviate things and try to move on. So, Mr. Clements you had proposed three-year contract terms in this case; is that correct?

A. That's correct.

Q. So, during those three years, would a QF be paid capacity payments based on a peaking resource?

A. It's possible depending on when they requested pricing and whether there was a peaking resource included in the Integrated Resource Plan.

Q. So, in the current IRP, is there a peaking resource included in the resource sufficiency period?

A. No. There's no deferrable resource included until 2028.

Q. Okay. So, there's nothing until 2028?

A. Yes.
Q. So, if a QF entered into a 20-year contract, how many years out does 20 years ago?
A. From today?
Q. Yeah.
A. 20.
Q. What's that?
A. 20.
Q. And what year does that get us to? Simple math here.
A. 2035.
Q. Okay. So, if a QF entered into a 20-year contract, they would be paid some resources based on the costs of a net, a new thermal resource acquisition starting in 2027 or 2028?
A. That's correct, yes.
Q. And if a QF entered into a three-year contract, they would not?
A. Under the current preferred portfolio, yes, correct.
Q. So, in the past, has the portfolio included a peaking resource, say, between a four- to seven-year period out?
A. I'm not sure the preferred portfolio has ever had a peaking resource in it, but there have been gas

plants that have been three to four years out.
Q. Okay.
A. In fact, back in the 2010, '11, '12 IRPs, we had gas plants stacked up in '14, '15, '16, '18. There was a whole line of combined central gas plants that were to be built that subsequently were deferred and not built.
Q. And those were three, four, five years out?
A. At the time, yes.
Q. So, if the QF had entered into -- if you had three-year pricing in effect or three-year contract terms in effect at that point and the QF entered into a three-year contract, they would not be paid based on the thermal resource because that's three to four years out.
The contract only goes three years?
A. Correct.
Q. So, if that QF renewed its contract in three years and the next thermal resource acquisition was out again another three years, they again would not be paid rates based on the thermal resource acquisition?
A. Yes, that's correct. That's a concern that I considered as well, that if you only have a three-year contract term, you're never going to catch up to the resource deficiency period because the Company will go out and acquire that resource when it needs it.

And I would agree with that issue. I would agree that Mr. Peterson's proposal somewhat addresses that issue with how he calculated the capacity payment for five years.

Q. Thank you. I appreciate you agreeing to that issue. Now, that cuts off the rest of my questions on that point. Have you read the testimony, the rebuttal testimony of Nathan Rich on behalf of the Renewable Energy Coalition, REC?

(Recess taken)

THE HEARING OFFICER: Okay. We're back on the record. We'll continue with Mr. Sanger.

BY MR. SANGER:

Q. Thank you. I think my last question was whether you read the rebuttal testimony of Nathan Rich on behalf of Renewable Energy Coalition; correct?

A. Yes.

Q. And does his company or his district sell power to PacifiCorp? Do they have a current contract with the company?

A. I believe they do. I'm not as familiar with our smaller QF contracts but I believe they do.

Q. So, in his testimony he describes his project. He describes it as a 300 kilowatt project. So, you're not familiar with that contract? You don't remember it?

A. No. I'm familiar with this project, though.

Q. Okay. Do you remember in his testimony where he talked about needing or entering into an 11-year PPA?

A. Yes, I recall that.

Q. And is this project a wind or solar project?

A. No, it's not.

Q. Now, can you refer to your rebuttal testimony on page 21? In this rebuttal testimony, you discuss the difference between small and large QFs and you discuss the Company's concern, the Company's more concerned with larger QF contracts. Is that still the case?

A. Yes, that's correct.

Q. So, what's the difference in your mind between small and large QF contracts? Why do you have a lower concern for the smaller contracts?

A. The primary difference is that -- so, the smaller contracts, if we're calling small less than three megawatts, the smaller contracts are subject to Schedule 37. And that particular tariff has a cumulative 25-megawatt cap in the tariff.

And the Company files that tariff once per year, typically. And so, under that tariff, the Company will receive no more than 25 megawatts worth of projects each year. And if there are requests exceed that amount, then the Company would need to file another tariff.

And i'm getting to the answer here. The primary concern with fixed-price risk is magnitude. And so, 25 megawatts worth of QFs do carry some fixed-price risk with a 20-year contract but that magnitude is reasonable.

Two thousand megawatts of fixed-price risk perhaps is not reasonable. And that goes back to my earlier comments where I'm not sure what that number would be but the 25-megawatt cap in Schedule 37 significantly decreases the fixed-price risk for those types of QFs.

Q. And that's even more so for a 300-kilowatt project?

A. Yes. That would be much less than the 25 megawatts. So, that risk would be further diminished.

Q. And moving on to your testimony at the bottom of the page 21, you talk about, you do not agree with the recommendation that capacity payments would apply to existing QFs even if the Company does not have a forecast capacity need during the three-year term.

And you then state that there's no guarantee that a QF will sell power to the Company at the expiration of any contract term.

And that is your testimony; correct?

A. That's correct.

Q. Now, are you aware that in the Integrated Resource Plan that the Company plans on small QFs renewing their contracts?
A. Yes. I believe that has been the practice. I'm not sure if it continues to be the practice.
Q. And at least historically, the Company has for the entire 20-year planning horizon assumed that the small QFs will continually renew their contracts?
A. I believe that's correct.
Q. So, in, say, 2027 or 2028, the Company is counting on a small QF being there and selling power to it in the IRP for the entire 20-year horizon which we determined would be out to year 2035?
A. Yes. If that's the treatment, then yes, it would. And again, the magnitude plays a pretty material role in that as the small QFs all added up equate to a fairly small amount of megawatts.
Q. And you participated in the Idaho Public Utilities Commission proceeding in which the Company also requested a three-year contract term?
A. Yes, I did.
Q. And did the Idaho Public Utilities Commission treat small base-load QFs differently than wind and solar QFs?
A. They did. They call it published-rate

contracts as opposed to small or Schedule 37. That's their distinction. But the published rate which are the small projects which I believe are ten average megawatts and below for hydro and base load and a hundred kilowatts and below for wind and solar, those projects continue to receive 20-year contract terms while the non-published rates which would be anything above that were limited to a two-year contract term.

Q. And did the small projects also, are they also entitled to capacity payments in their contract renewals?

A. Currently that's the methodology in Idaho, yes.

Q. And the resolution of that proceeding where small QFs obtained 20-year contracts instead of the shortened contract term, would that sort of distinction between small and large QFs, would that be a reasonable resolution? I know that's not the Company's position but is that within the zone of reasonableness that the Company could accept?

A. Yes. I would agree that's reasonable in that the primary concern that the Company has in this docket is protecting customers from fixed-price risk.

And fixed-price risk really rose with the magnitude of megawatts. And with the small projects being limited to 25 megawatts cumulative for each year, that risk is much smaller.

MR. SANGER: No further questions.

THE HEARING OFFICER: Thank you. Ms. Hogle, any redirect?

REDIRECT EXAMINATION

BY MS. HOGLE:

Q. I just have a few. Thank you. Mr. Clements, Mr. Ritchie in earlier cross-examination asked you about the Company's forecast used to justify the acquisition of capital additions. Do you recall that discussion?

A. I do, yes.

Q. So, when the Company purchases fuel for those capital additions, does the Company execute long-term contracts or does the Company execute short-term contracts?

A. For the natural gas plants, typically the contracts are short term in nature within the 36-month hedging horizon that I spoke of unless there is a specific economic opportunity that's well vetted before all stakeholders which occurred. The Company did go out and acquire some ten-year fixed-price gas at a very small volume.

But typically the gas plants are not hedged beyond the 36-month time period. There are some coal contracts that go longer in nature which is the nature of most coal supply agreements. But for gas, no.

Q. And in cross-examination, you were also asked whether you could quote a decision where a court or commission limited a QF term and found that this does not violate PURPA. Do you recall that line of questioning?

A. I do.

Q. Is it your understanding that on reconsideration, the Idaho Commission just very recently affirmed its earlier order that PURPA in its implementing regulations do not require a specific number of years or establish a certain time period for PURPA contracts?

A. Yes. The Idaho decision which was upheld on reconsideration by the Idaho Commission, they made it clear that the Commission did have the legal right to set the contract term.

Q. And do you recall another decision in the country where that was found to be the case?

A. Yes. I couldn't recall it previously and didn't want to get the details wrong, but there was an excellent wind case or a case involving Exelon Wind in Texas where the 5th Circuit upheld a Texas Commission decision which allowed the local utility there to limit the contract term for firm sales.

Q. Okay. Mr. Clements, you were also asked about your position on the hedging guidelines and what ensued as a result of the hedging collaborative.

Do you recall that line of questioning?

A. Yes. Very much.

Q. Do you know what the Company's current risk management and training policy is with respect to contract term?

A. Yes. So, the traders who manage our position on a daily basis are limited to 36 months for natural gas and electricity hedges, and they cannot exceed that amount without upper management approval or on the case of natural gas, there's additional requirements.

Q. And why did the Company limit the term for those hedges?

A. So, the Company had a similar term, it was slightly longer, I believe 48 months, but they limited it to 36 months primarily, again, in response to the hedging collaborative. And without getting into the weeds of that discussion again, it was primarily in response to stakeholders saying, we don't want you, Company, to take long-term fixed-price positions because that introduces price risk that we don't want customers to bear.

And I know there are a lot of details that Mr. Dodge and I discussed in that particular collaborative, but that policy was put in place in response to that stakeholder desire to limit the fixed-price exposure to customers.

Q. Okay. In cross-examination, you were also asked about the ratepayer indifference standard and Utah's policy to encourage the development of small power production.

Do you recall that line of questioning?

A. I do.

Q. Is it your understanding that the must-purchase obligation and the exemption of QFs from federal and most states, most federal and most state laws and regulations are built-in provisions within PURPA that serve to encourage the development of small power production?

A. Yes. And that's where the Commission has the ability to implement PURPA in a manner it sees fit and it strikes a balance between encouraging the development which is consistent with Utah statute and protecting customers which is consistent with PURPA legislation that requires ratepayer indifference. And sometimes that requires a policy decision.

And an example of that is the ownership of renewable energy credits. I believe in the order in the 12-035-100 docket, the Commission actually referenced that portion of code -- I may be wrong but that's my recollection -- as one of the reasons why the RECs should stay with the QF.

And so, the Commission can determine what's fair within its purview. And in my opinion, it's not fair to customers to saddle them with a limitless amount of fixed-price risk. And I believe that would be consistent with Utah statute and with PURPA.

Q. One last question, Mr. Clements.

Would you agree with me that another policy of the state of Utah is to have a target amount of qualifying electricity?

A. A target amount of renewable electricity?

Q. Yes.

A. Yes. A renewable portfolio goal I guess you would call it. RPG. I don't know what the official term is.

Q. And would you agree with me that that goal, pursuant to Utah statute and that the statute indicates expressly that it should be met or it's a goal provided that the renewable energy is cost effective?

A. Yes. There is the customer protection that that energy needs to be cost effective. And it also highlights the issue I raised earlier where, I'm not sure that a QF would meet that requirement because we do not get the renewable energy credit.

And again, we don't know all the details about how that's going to work out with the Utah clean power act and some of the other environmental issues coming down the road, but not getting the environmental attribute from QFs will certainly be an issue.

MS. HOGLE: Thank you.

THE HEARING OFFICER: Any recross from the Division, Mr. Jetter?

MR. JETTER: No. Thank you.

THE HEARING OFFICER: Mr. Moore?

MR. MOORE: No.

THE HEARING OFFICER: Ms. Dutton?

MS. DUTTON: No.

THE HEARING OFFICER: Mr. Ritchie?

MR. RITCHIE: No.

THE HEARING OFFICER: Mr. Dodge?

MR. DODGE: No.

THE HEARING OFFICER: Could we have somebody close that door in the back?

(Brief break)

THE HEARING OFFICER: Mr. Sanger?

MR. SANGER: No.

THE HEARING OFFICER: Thank you, Mr. Clements. You're excused. Oh, yes. Sorry. Commissioner White?

COMMISSIONER WHITE: None for me, Chair Lavar.

THE HEARING OFFICER: Okay.

Commissioner Clark?

EXAMINATION

BY COMMISSIONER CLARK:
Q. I want to take you back to your conversation with Mr. Sanger about IRP planning and QFs with short-term contracts. And I'd like you to, rather than look historically to look prospectively, assuming that the application is granted and that the maximum term is adjusted to three years.
Has the Company determined how it would address the capacity related to QF projects under these short-term contracts from an IRP perspective, how it would address them in its planning?
A. In terms of whether the Company would assume they would continue?
Q. Well, I think that's probably the fundamental question, yes.
A. I think we would have to evaluate that on a project-by-project basis. Some projects have shown an inclination to sell to other parties while some projects have made it clear that they have no other market alternatives. So, we would have to look at that and determine what's most appropriate in that scenario.
Q. Do you see any system reliability issues related to this scenario from a planning perspective going forward?
A. I do. And without rehashing what ground we've

covered in the 12-035-100 docket, we allow this partial displacement method where we say that a solar or a wind project can partially displace the gas plant in 2028.

If we have enough QF projects come on, wind and solar let's say, arguably, you could displace that entire resource on paper through the method. Yet, I'm not sure that three or four thousand megawatts worth of wind and solar are going to provide the capacity products that we would get from that from that gas plant such as operating reservations, load following services, voltage control, some of those things that might be required.

And so, from a reliability standpoint, yes, I do have concerns about replacing some of the base-load dispatchable units with non base-load intermittent resources, yes. I apologize for the lengthy answer there.

COMMISSIONER CLARK: That's all my questions. Those are all my questions.

THE HEARING OFFICER: Thank you. And I don't have anymore. So, thank you, Mr. Clements.

THE WITNESS: You're welcome.

THE HEARING OFFICER: Ms. Hogle?

MS. HOGLE: The Company rests.

THE HEARING OFFICER: Thank you. Mr. Jetter?

MR. JETTER: Thank you. The Division would like to call Charles Peterson as its witness.

THE HEARING OFFICER: Mr. Peterson, do you swear to tell the truth?

THE WITNESS: Yes.

THE HEARING OFFICER: Thank you.

CHARLES PETERSON,

having first been duly sworn, was

examined and testified as follows:

DIRECT EXAMINATION

BY MR. JETTER:

Q.   Good morning, Mr. Peterson. Would you please state your name and occupation for the record today?

A.   Yes. Charles E. Peterson, P-e-t-e-r-s-o-n. And I'm a technical consultant for the Division of public Utilities.

(DPU Direct, Rebuttal, and Surrebuttal Testimony of Charles Peterson identified)

BY MR. JETTER:

Q.   Thank you. And in the course of your employment with the Division of Public Utilities, have you had the opportunity to review the application filed by the Company and after doing so, have you created or caused to be created and filed with the Commission direct, rebuttal, and surrebuttal testimony in this docket?

A. Yes, I have.

Q. Are there any corrections that you would like to make in any of those?

A. None that I'm aware of.

Q. And if you were asked the same questions today that are contained in those three prefiled testimony documents, would your answers be the same?

A. Yes.

MR. JETTER: Thank you. With that, the Division would move for the admission of Charles Peterson's direct, rebuttal, and surrebuttal testimony into the record in this hearing.

THE HEARING OFFICER: If any party objects to that, please indicate. Hearing no objection, that will be entered. Thank you.

(DPU Direct, Rebuttal, and Surrebuttal Testimony of Charles Peterson Admitted)

BY MR. JETTER:

Q. Thank you. Mr. Peterson, have you prepared a brief summarization of the position of the Division of Public Utilities in this matter?

A. Yes, I have.

Q. Please go ahead.

A. I think it's still morning. So, good morning commissioners. The Division generally supports

PacificCorp's request to reduce the maximum contract term for QF power purchase agreements.

As noted by Mr. Clements, the Company has experienced an extraordinary increase in QF applications in the last couple of years, something that was not foreseen by anyone a few years ago.

The problem is the potential to lock in substantial amounts of intermittent, nondispatchable resources at long-term prices while at the same time holding dispatchable resources as backup. The long-term prices create risk to ratepayers, something that you've heard a lot about so far.

As a way to mitigate the problems that could arise as a substantial portion of the QFs get built including likely higher prices to ratepayers, PacificCorp is proposing reducing the maximum QF contract term from 20 to three years.

For reasons set forth in my direct testimony, the Division is suggesting a modification of the Company's proposal to a five-year term but also to allow a QF to receive capacity contribution payments over the five-year term as based upon the present value of the capacity over 20 years similarly to the way it's done now.

Every five years the pricing would be updated including the capacity payments. Other parties in this docket have uniformly opposed making any change to the status quo. However, in my opinion, none have proposed an alternative solution to the potential problems faced by the Company other than to suggest that low avoided cost pricing would eventually discourage developers.

The prediction of what that low avoided cost price level is by one intervenor expert witness has already failed. Generally, the opponents of a change make three arguments.

One, PacificCorp and Utah generally needs all the renewable generation resources it can get to mitigate various environmental concerns and the federal and state laws set a policy to support renewable resource development.

Two. Renewable resources are substantially just like Company-acquired resources in that the use of avoided cost pricing and the Company's IRP to determine the next deferrable resource makes it irrelevant whether the resource is acquired today or in 2028 or later.

And three, reducing the maximum contract term will make it nearly impossible for QF developers to obtain financing, thereby reducing QF developments in Utah to essentially zero.

The Division does not believe that federal and state policies contemplated the occurrence of unrestrained limitless development of renewable resources. You can get too much of even a good thing, and the Division is concerned that we may be heading down that road. Proponents of the Company's proposal strain to show that QF development is just like Company-acquired resources. They emphasize some similarities but largely ignore or downplay the differences.

For example, the Company has to pay power when the QF generates it no matter whether or not the power is needed on that day and hour and whether the cost is economic.

Company-acquired resources aside from the Company's own renewable resources can generally be dispatched when it is needed or when it is economic to do so.

As I've indicated in my testimony, the Division believes that the financing issue is overstated; that is, there are possibilities for financing if a developer wants to pursue them.

Of course a developer cannot be forced to pursue alternative financing or do anything at all if it doesn't want to. The Division does recognize that the 20-year term is a benefit to developers and that reducing that benefit will likely reduce development.

In Docket Number 03-035-14, PacificCorp witness Bruce Griswold supported the 20-year contract term limit versus a request for 35 years as, quote:

"... an appropriate balance between a term that allows the QF to secure financing and limiting the risks that accompany long range power price forecasting."

The Division believes that it may be time to reevaluate whether this balance between benefiting QF developers with 20-year contracts and the risks assumed by ratepayers that Mr. Griswold testified to ten years ago is still intact.

The Division's position can be questioned regarding a couple of other issues.

First, the Division has in the past not opposed longer contract terms in an effort to be supportive of the relatively few renewable QF projects that have come through and focused on assuring that the contract pricing appropriately reflected avoided costs and the methodology that was approved by the Commission and, to a lesser extent, other contract terms that seem to affect whether or not ratepayers can rely on the projects being built in a timely fashion.

Second, the Division suggested an alternative to a term of five years but with a capacity payment based upon a 20-year forecast as is done today has been criticized for contradicting the ratepayer indifference standard since the developer could be paid for a capacity payment as if it were going to be in place for 20 years but then opt out after as few as five years.

This part of the Division's proposal is not consistent strictly speaking with ratepayer indifference.

However, if the Commission orders a reduction in the contract term, then ratepayers would still be better off generally.

And under that condition, the Division believes that it is appropriate to give some additional encouragement to renewable developers beyond the must-buy requirement of PURPA which also is a benefit to developers.

At this time, the Division believes that the risk of a QF developer opting out after five or 10 years is small based upon the fact that the developer has chosen the QF route to begin with as the best option available to it. But of course the future will likely be different than anyone of us expects.

And that concludes my statement.

MR. JETTER: I have no further questions for Mr. Peterson. He's available for the parties to cross-examine.

THE HEARING OFFICER: Okay. Thank you.

Ms. Hogle, do you have any cross-examination?

CROSS-EXAMINATION

BY MS. HOGLE:

Q. Just a couple. Mr. Peterson, you were in the room when Mr. Dodge was asking Mr. Clements about his recollection of the scope of the hedging collaborative workshops. Do you recall that?

A. Yes.

Q. Did you participate in those hedging collaboratives?

A. Yes.

Q. Can you tell us what your recollection was with respect to the scope of the hedging collaboratives?

A. My recollection is is that the intention of the hedging collaborative was to limit the Company to 36-month contracts. And these also included not only financial contracts; swaps, typically, but also the physical commodity contracts.

And in fact, I've also participated in the Division's review and audit of the Company's annual energy balancing account filings, and the Division's audit is consistent with the view I just stated.

We look at the physical as well as the financial transactions that the Company entered into and we attempt to verify that they are consistent not only with the 36-month term limit but also with the percentages that the collaborative restricted the company to over that 36 months.

Q. So, there's no distinction between gas and the electricity hedging contracts; is that correct?

A. In the Division's view and in the way that we have applied it to the energy balancing account, the answer is no.

MS. HOGLE: Thank you.

THE HEARING OFFICER: Is that all?

MS. HOGLE: Yes.

THE HEARING OFFICER: Mr. Moore?

MR. MOORE: The Office has no questions. Thank you.

THE HEARING OFFICER: Ms. Dutton?

MS. DUTTON: Utah Clean Energy has no questions.

THE HEARING OFFICER: Mr. Ritchie?

MR. RITCHIE: No questions. Thank you.

THE HEARING OFFICER: Mr. Dodge?

MR. DODGE: Sorry. I do have some.

THE WITNESS: I'm not surprised.

CROSS-EXAMINATION

BY MR. DODGE:

Q. Mr. Peterson, first I'd like to clarify your testimony. It is not your testimony here that reasonable financing terms are available to a developer of a renewable energy project with a five-year PPA; is that correct?

A. It is correct, but I cannot specifically identify that those terms are available.

Q. In fact, in response to a data request from the Coalition, you said we were mischaracterizing your testimony because it's not your position, you haven't taken the position whether reasonable financing would be available on a five-year term; correct?

A. That's correct. Specifically, I answered that we think that the financing world has changed from where it was ten years ago when the Commission previously reviewed this issue.

Q. Right. And I'd like to go through that with you briefly, but first of all, you also complained that there's been no hard evidence that there's not available financing. You said that in your testimony; is that right?

A. I did say that but I also have subsequently provided examples where such short-term contracts or shorter term than 20-year contracts have been entered into.

Q. And we'll talk about that in a minute.

You understand that asking intervenors to provide hard evidence that financing is available or that financing would not be available with a short-term PPA is asking them to prove, A, a negative and, B, a situation they haven't faced before.

Do you understand those two things?

A. Well, in the sense that I'm asking them to approve a negative, it may be difficult for them to do so, although I can conceive of a scenario in which they might be able to demonstrate it with a high probability. But then the alternative is is to show that they have been financing less than 20 years.

Q. And we'll talk about that.

You also understand that the proponents of the change to a policy have the burden of proof.

You understand that, too; do you not?

A. Yes.

Q. You said you believe that there is some evidence that perhaps financing might be available to short-term PPAs. And I want to go through each of your examples and let's talk about it.

But let me start by saying, let's say that you were persuaded that there will be zero QF renewable projects done in Utah for so long as there were a three-

or a five-year term. Let's pretend as a hypothetical.
A. So, that's the sole reason that there would not be --
Q. Because of the term.
A. Okay.
Q. Because of the three- or five-year term, the projects that are now being developed wouldn't have been developed and the projects that might come forward in the future won't be.
Let's assume that as a fact, recognizing we don't have that evidence one way or the other.
If that were the case, would your view be that the Company's proposal or the Division's proposal to limit the term would be consistent with Utah statute that states the state policy to encourage the development of these types of projects?
A. I think that the Division or the Company's burden of proof would be higher to show that it was still consistent if -- solely because of the reduction in turn, there would be exactly zero development made or that it would even be possible for zero development to be made or more than zero development. I think that would be concerning, yes.
Q. You complain that there's no hard evidence. But I'd like to talk for a minute about the evidence that

is in the record. First of all, you've seen evidence in the record that 20-year PPAs for QFs is the industry standard throughout the country.

You've seen that testimony?

A. I believe I have seen that stated. I don't dispute that that would be the common contract language.

Q. We know from experience in Utah that a 20-year PPA, at least in the last two years, has been sufficient to encourage the development of renewable projects and get projects financed and constructed; correct?

A. All the QFs that I have -- contracts that I have reviewed are 20-year contracts.

Q. And so, that is working. We know that 20 years is working ing to encourage it. But there's no evidence, is there -- well, I'm not going to ask that question because we're going to go through that now.

You accept that -- you're not a financing expert, is that right, of renewable energy projects?

A. I have not worked in that arena of financing renewable energy projects.

Q. And you accept that every witness in this docket who can claim to be an expert in actual financing renewable projects has said they won't be able to get them developed if the term is reduced to three or five years. You're aware of that testimony; right?

A.   Well, I'm aware, yes.
Q.   Okay. Now, you've indicated several times in your testimony here -- excuse me, in your prefiled testimony and in your summary that you think there's some evidence that the financing situation might be changing for renewable projects; right?
A.   Yes.
Q.   I'd like to walk through that evidence that you cited and talk about whether that does provide any support for the notion that short-term PPAs are financeable for renewable projects.
First of all, you reference the concept of yieldco; correct?
A.   Yes.
Q.   Do you understand that yieldcos are an alternate form of sponsor equity in a project as opposed to either tax equity or debt?
A.   I understand that there are various flavors of yieldcos and but, basically, the developer can sell his project into a yieldco possibly making a profit on the sale and then receive dividends back out from the yieldco.
Q.   I guess, let me ask my question more directly.
Do you understand that an entity that uses a yieldco to help finance a project typically also has to

obtain debt from more traditional debt sources?

A. Yes. I understand that there is debt and equity involved in both the developing company or sponsoring company and in the yieldco.

Q. So, when you point to the fact that the yieldco may be a new financing option, you understand that a developer has to come up with a combination of debt and equity to make the project work, that will make the project work; correct?

A. Presumably, yes.

Q. You also understand, do you not, that an investor or a lender would view a PPA with five years as having greater risk than a PPA with 20 years fixed prices?

A. Generally, yes.

Q. And with increased risk, investors or lenders expect higher rates; do they not?

A. That would be the traditional financial theory.

Q. You specifically referenced one of the participants in the Coalition that I represent, SunEdison, and their use of yieldcos.

And you reference to the fact that they were going to maintain a portfolio of projects for a certain period of time and then potentially drop it into a yieldco; right?

A. Yes.

Q. You understood, did you not, that the average remaining length of term for all of those PPAs that were involved in that particular transaction was 18 years?

A. Yes. That's what the news release said.

Q. And that was remaining years presumably at the time the PPAs were entered -- did you understand these PPAs were entered into by a utility and they were being purchased from them?

A. Yes. I understood that. And the 18 years is a weighted average. So, there would have been contracts or projects there that would have had presumably more or less than the 18 years.

Q. Left; correct?

A. Left.

Q. You don't know whether every one of them, when initially financed and built, was a 20-year or a 25 or some other number? What you know is what's left at the time of the transaction according to the report was 18 years; right?

A. That's correct.

Q. And you pointed out that Sun Edison's CEO or CFO, I forgot which, had indicated that maybe those would be held within the Company for up to seven years and at some point perhaps dropped into a yieldco; is that right?

A. It was the CEO as I understand it, to make that clarification. Yes. The Company Sun Edison has created yet another vehicle which contained a warehouse to hold the purchase of these assets and the financing is provided over a seven-year term. I think JP Morgan was the funder of that financing.

And the intention certainly is is to drop those projects into the yieldco as the yieldco is able to purchase the amount of the warehouse. That's my understanding of what's going on there.

Q. But didn't you suggest that because they could be held as long as seven years in that warehouse before being dropped into the yieldco, meaning that there would be a weighted average of 11 years left of that time, that that somehow demonstrated that financing an 11-year PPA might be possible?

A. Yes. And I'd be happy to explain my thinking about that. What that demonstrates is is that a yieldco, when it receives a project, is not requiring that the project already have or have a 20 years remaining which also suggests to me that there is no magic number that the yieldco has to have a 20-year contract when it first acquires the project or even an 11-year contract when it first acquires it.

The idea is is that the yieldco acquires a project with the remaining contract that may be just a remaining but it can be as low as 11 years or, depending on what the original contract term distribution was, it could be under ten years.

Q. But you understand, do you not -- let's pretend for a moment, another hypothetical, that each of those projects that you're referencing was a 20-year PPA. Now it's sold with 18 years left, and then you're saying maybe with 11 years left it's dropped into a different yieldco financing mechanism.

You understand that the investment at year one for a 20-year PPA -- I'm going to make up a number, it may have been $100 million. Two years later the remaining investment that has to be recovered might be lower than that, 18 -- you know I said a 100 million. $90 million. Let's just pretend.

Seven years later when there's only 11 years left, the remaining investment might only be $50 million; right? In other words, the amount that the investor is putting at risk is going to change as the project depreciates and that investment is already recovered; correct?

A. Well, that depends on -- you're making a lot of assumptions there. But the value -- I'll go this far with you. The value of the project will be different for a -- if it has a 20-year PPA than if it has an 11-year PPA, but my point is is that the yieldco and its investors -- and the yieldco has a separate set of investors who financed it -- are willing to take in projects, apparently, with contract terms that are potentially much less than the 20 years that you're proposing.

Q. But the risk is also half as much or almost half as much 11 years in. The remaining amount to be collected is reduced significantly. The risk is reduced significantly, and these are already constructed projects that presumably required 18 or 20 years to get financed and built in the first place; right?

A. Well, presumably, but you've said the risk is reduced. So, that would make the value higher again under typical finance theory.

Q. But what we're dealing with is the encouragement of the development of a QF resource. Nothing about the fact that a depreciated resource already built eleven, seven or eight years or nine years into its life might be financeable or might be traded to someone for the remaining risk, for the remaining life.

Nothing about that speaks to what it takes to get it built in the first place; does it?

A. I think that it does. I think that it shows that the yieldco as a financing vehicle for the sponsoring developer may be willing to accept, say, a ten-year contract as part of its portfolio.

Q. You've seen testimony, have you not, in this docket that the average PPA length of yieldco is at least, that Mr. Isern knows about, 15 to 20 years and that's about what the average yieldco PPA remaining life is? Do you remember reading that testimony?

A. Not specifically, but if you want to represent that that's what he said, then I won't dispute that.

Q. He can speak to that, but the point I'm trying to get to, and you seem to be resisting me -- maybe we need to go through some of this -- is that yieldcos are viewed as a means to provide a different kind of equity for long-term PPAs that are already there for investors who want to invest in them.

You haven't shown any testimony or any evidence, have you, that a yieldco was willing to invest in a short-term PPA from the get-go as opposed to buying a depreciated set of assets years into the development or into the development?

A. Well, yieldco's are relatively new and how they may evolve into the future is anyone's guess at this point. My point in bringing up the subject of yieldcos is that they are a new animal that did not exist ten years ago when the Commission last reviewed this issue of term contract term limits. And that a yieldco might in the future as part of its overall portfolio support a contract that has five or 10 years on it is something that I can at least conceive of.

Q. As someone who's never done it; right?

You could conceive of it, but you don't have any experience that would suggest that's true; do you?

A. Well, to the extent that there is evidence available to this relatively new animal, I think I presented evidence that yieldcos are not locked into making 20-year contracts.

Q. Do you accept the notion that yieldcos are premised upon the fact that there are long-term PPAs with creditworthy utilities backing the return and therefore they can be sold to these yieldcos, these individual investors who buy into the yieldco at perceived low risk and relatively low rates at least right now?

Is that consistent with what you understand of yieldcos?

A. Well, I think that's consistent with what some yieldcos are aiming at, but I've read also where there's been complaints already in the media where yieldcos have taken in projects that maybe are not what -- or maybe not the quality that have been expected.

Q. And indeed, if they started taking in five-year PPA projects, there would probably be a lot of complaining about lack of long-term stability and high risk; right?

A. Well, it would depend on what portion of the portfolio it was.

MR. DODGE: May I approach?

THE HEARING OFFICER: Yes.

BY MR. DODGE:

Q. I'd like to hand you -- and I have all of them if you'd like to look at them.

Mr. Peterson, in your testimony, you provided web sites, links to web sites for five or six articles describing this new yieldco entity; correct?

A. Yes, I did.

Q. This new yieldco concept?

A. Right, in order to provide some background information.

Q. And I trust you read through those articles?

A. Yes.

(RMCRE Cross Exhibit-3 identified)

BY MR. DODGE:

Q. And I have the entire articles here if you'd like to see them in context. What I've done in this that I'd ask to be marked Coalition Cross Exhibit-3 I believe,

what I've done is highlighted certain paragraphs from several of those articles. And I'd like to see if you understood this as you talked about yieldcos.

And I turn to the first one which was in this Social CSP Today. And in the highlighted part, I'd like to read it and you tell me if this is consistent with your understanding.

"Yieldcos are essentially publicly-traded holding companies which bundle assets that produce a steady and predictable flow of income, such as energy plants, that have long-term distribution agreements."

Did I read that correctly?

A. Yes.

Q. The next highlighted part:

"While they can face many uncertainties during bidding, permitting and development, once they are connected to the grid their cash flows are low-risk, because they typically generate a steady income from 20 or 25-year PPAs or tariffs, once in operation."

Now, is that consistent with your understanding that yieldcos are viewed as low risk because they have long-term PPAs?

A. I would agree that that's what the statement says.

Q. And again, these are what you cited in your testimony to explain what yieldcos are; right?

A. Right.

Q. If you'll turn to the next highlighted part, this is a Bloomberg article, the highlighted part. And I will read it.

"In thinking about how to value yieldcos, it is vital to understand that they are, at the end of the day, portfolios of projects. Any yieldco valuation has to start with a valuation of its underlying projects, and any premium over that value needs to be carefully justified.

"Most wind and solar projects have a life of 20 to 25 years. Revenues over the first 15 or so years are often underpinned by feed-in tariffs, power purchase agreements, or long-term green certificate sales arrangements."

Again, consistent with the notion that why yieldcos have become popular is because they have long-term sustainable power purchase agreements; right?

A. Right. I'll just point out that this does not -- this says revenues over the first 15 years or so. So, again, it's a break from the 20 years.

Q. So, 15 years, they're saying at least 15 has a guaranteed amount but it doesn't say anything about five

years; does it?

A. No.

Q. And we don't want to read all of these, but I'd invite you to look at the highlighted parts where they talk about the risks of yieldcos are when they drop off the end of the PPAs. There's one here under UBS that talks about a contract tenor of ten to 20 years. They talk about significant expiration risk.

I guess my point is, isn't it inconsistent with the whole concept of yieldcos as you understand them based on your review of these articles that putting into them short-term PPAs with high risk when the goal here is long-term low-risk assets that investors can invest in without as a high of a return expectation as another equity investor might expect?

A. I would agree that the goal is to put in as least risky assets as they can find and that a five-year contract term is less risky or is, excuse me, is more risky than a 20-year contract term.

MR. DODGE: Thank you. I'd move the admission of Cross Exhibit-3.

THE HEARING OFFICER: If any party objects to that, please indicate. It will be admitted. Thank you.

(RMCRE Cross Exhibit-3 admitted)

BY MR. DODGE:

Q. One of the other pieces of evidence you referred to, Mr. Peterson, for the notion that financing might be changing is balance sheet financing, the possibility that a company might just choose to take a project on its own balance sheet.

What if Rocky Mountain Power came in here and said, we'd like to finance a hundred percent of our next power plant with equity, would you object? Let me add, with the equity return that they are offering.

A. With the equity return that they are authorized? No, I don't think the regulatory -- I think there would be objections to that and I would object to a hundred percent, the equity financing as being imprudent in the sense that it was not minimizing costs.

Q. And that's because equity is much more expensive. Most people expect more return when their equity's at risk than a debt lender who's first in line to be paid back; correct?

A. That's generally correct, yes.

Q. And so, it would be imprudent for a utility to finance a hundred percent of its investment with equity.

Would it not also be imprudent for a public company or a privately-held company that has shareholders, stakeholders, to not leverage its equity in the manner you're suggesting by using balance sheet

financing? In other words, it would be the exact same concept and would be using high-priced equity that would not allow the return that the Company's expect from thereafter.

A. Well, a balance sheet financing to me means using both debt and equity components. So, I would expect even a Sun Edison or a similar publicly-traded company or a privately-held company would use a mixture of debt and equity in any financing they would do.

Q. So, it gets back to, then, what do the debt and equity markets expect in terms of financing this kind of project; correct?

A. Yes.

Q. You also reference a few short-term PPAs and I'd just like to make sure we're communicating correctly. When you try and give examples of some PPAs that maybe have been financed with shorter terms, you reference the one in the testimony of the renewable energy Coalition that you say has a 11-year contract; right?

A. Yes.

Q. You understand from the testimony here this morning and your reading of the testimony of Mr. Rich that that's a municipal solid waste combustion facility; right?

A. Yes.

Q. And it was built in 1987 nearly 30 years ago?
A. Yes.
Q. And municipalities have different financing options than do private companies?
A. I pointed that out in my testimony.
Q. So, it doesn't go to show that a company trying to develop a renewable energy project can finance an eleven-year contract but it shows us one that's built and that's 30 years depreciated might be willing to sign an 11-year contract; correct?
A. Well, I think that it goes to the issue that we are dealing with or talking about QF contracts generally and not specifically about whether a private developer can come in and develop an 80-megawatt QF project. So, to me, the financing available to a municipality or some other not-for-profit company can be completely different than what SunEdison requirements are.
Q. Exactly. But it doesn't support the notion than an 11-year PPA can be financed by projects that are just now being constructed as opposed to one that's been depreciated for 30 years, correct, this example, because you used it --
A. I think I would accept that, but it doesn't support the idea that a new greenfield project would be 11 years.

Q. You also referenced three projects in Washington that the Company referenced in a data response; correct?

A. Yes.

Q. You understand those are all under two-megawatt projects?

A. I understood that they were what we call small QFs, yes.

Q. And none was wind or solar?

A. I'm not familiar with what they were. We just asked them about QF projects. Again, the issue is not necessarily what type of technology is being used.

Q. Would you accept subject to check that DPU data request 3.2 said how many renewable projects counted under 3.2(a) above are wind or solar QF projects?

A. Okay.

Q. And the answer was none.

So, the three projects they referenced in A, none of them is wind or solar.

A. Okay. I had forgotten that little tidbit.

Q. And so, you don't know who did those projects, how they were developed, how they were financed, why they were financeable with a five-year PPA.

You didn't investigate any of that; correct?

A. No. It didn't seem to be relevant.

Q. So, it doesn't really support the notion that a project, if the goal is to encourage the development of renewable projects in Utah, that three nonrenewable small QF projects in Washington that somehow got built would suggest that other projects in Utah could be built with just five-year PPAs; does it?

A. Well, I think the original impetus to ask me that question about Washington was that we learned that Washington had already had a five-year limit on contracts. So --

Q. On which contracts?

A. On the QF contracts.

Q. On which QF contracts? Under two megawatts?

A. Well, the under two megawatt but --

Q. They don't on large projects; do they?

A. I don't know what the Washington law is there, but on small QFs, they are limited to five years, and that seems to me to be the relevant point here. So, those projects, whatever they are, biomass or whatever, were developed under a five-year contract.

Q. But it's also relevant, is it not, that Washington doesn't limit larger QFs to five years?

A. Well, the point is is that it gets back to this issue of whether something is financeable or not as a QF for a term that's less than 20 years. And the answer is yes. There are possibilities to finance projects whether they are two megawatts or 80 megawatts or whatever. They are possibilities --

Q.   And they may all be municipal waste projects.
You don't know; correct?

A.   Well, if that's what they are --

Q.   I don't know. I'm asking you, do you know?

A.   Well, I don't know. And to me it's irrelevant.

Q.   You also reference, you said you did a quick Internet search and came up with a First Solar project in California that had 11 years on the PPA; right?

A.   I said 11 --

Q.   Or ten years?

A.   Ten years.

Q.   Did you also read in the article that you cite that, in addition to a ten-year PPA with Roseville, the municipality, that the owner of that also had a backup PPA with Pacific Gas and Electric?

A.   I remember reading something to that effect.

Q.   Do you think that backup PPA would also go into a financing entity's willingness to consider financing that project? Do you know if that PPA, for example, is a 20-year contract?

A.   I don't know.

Q.   Or a ten-year at the end of the ten years?

Without knowing that, you can't really cite it as an example of something that can be financed with just the 10-year PPA; can you?

A. Well, I think it shows that there was a ten-year contract that was entered into and at the end of the ten years, it's up in the air what would happen after that. So, there is a risk to any developer or whoever was financing that that the subsequent contract might not be available.

Q. But this article said there is a backup contract. I'll read it and I'll give it to you if you like. "First Solar has an additional PPA for lost Hills' output with Pacific Gas and Electric which goes into effect in 2019."

They have a backup contract with an investor-owned utility. You don't know the length of it. Neither do I. But it doesn't support the notion that that ten-year contract with a municipality was sufficient in and of itself to get this financed; does it?

A. Well, it may not have been sufficient in and of itself, but there's still a risk about the 2019 contract.

Q. So, I guess my point is, you reference other financing projects but you have not been able to point to one greenfield renewable project that has been financed with a short-term PPA despite whatever research

you've done; right?

You haven't shown us that there's even one?

A. Well, I think the Washington PPAs.

Q. Well, and you know nothing about them. You know don't know if they're greenfield, brown field, municipal?

A. Well, my understanding is is they would have had to have been developed under the five-year term, under the five-year contract.

Q. Mr. Peterson, you say that you're concerned about ratepayer risk and you said in your testimony that you assume there will likely be higher prices as a result of these QFs. Is that really your testimony?

A. The testimony is is that if we get this mass of QFs that are potential, that that would likely raise prices to ratepayers because the Company would have to maintain its existing fleet, essentially, intact to supply backup power and so on when the wind doesn't blow or the sun doesn't shine. And yet we'd have to pay the contractual amounts of the PPAs. That's when its potential for ratepayers to pay higher prices.

Q. You use the word "likely." It's equally likely the price will be below what the then available price is; is it not?

A. Well, if gas prices continue to plunge, I guess it could be lower, but if you assume that they stay the same, again, it's the idea that the Company's going to have to maintain a certain amount of its existing fleet as backup to, you know, an additional 2,000 or 3,000 megawatts of solar or PPAs.

Q. That's factored into the price, the avoided cost pricing.

A. Well, we can get into that if you'd like, but I'm saying, if that were to occur, there's going to be reliability issues that Mr. Clements testified to and I think there's potentially higher prices alternately to ratepayers because of the intermittency and the fact that you have to support, now essentially have to support two electric generation systems, the QF generation system and the backup system.

Again, this is all under the assumption that all of this two or 3,000 megawatts gets built.

Q. And do you believe that's going to happen?

A. I don't personally think it's going to happen.

Q. You heard what QF prices are today, in the 30s you said or maybe 40s?

A. I think in the low 40s or upper 30s is correct.

Q. So, you're representing ratepayer interests here in your concern, and you ask me as a ratepayer, would you rather take a $30 fixed 20-year resource for

energy with no fuel-price risk and no environmental risk or go on the short-term market for that same amount of energy for the next 20 years, what do you think my reaction would be?

A.   Well, I know what your reaction would be.

Q.   And I'm here representing ratepayers who have the same reaction among others. I mean, does that surprise you that the ratepayer advocates here are saying these are good deals if we can get them?

A.   Well, I think it's more complicated than you're making it sound because, again, if you're going to get 3,000 megawatts of generation at $30 a megawatt hour, to follow on your hypothetical, you still have -- the ratepayers are still going to have to pay for substantially all of the system that the Company currently has. And it may turn out that that will increase the price to ratepayers.

I don't know that for a fact but it seems like a good possibility under my hypothetical.

Q.   Does it not seem just as likely that the opposite will be true, that gas prices will go up, and so, by displacing market purchases at this 30 to $40 range, you're saving money?

Does that not seem as likely as the other?

A.   Well, we're talking about risk. And risk has to do with the variability of prices, not whether they're higher or lower. And the longer term -- the longer you go out, the greater the risk in terms of price volatility.

Q. I understand that. I was addressing your statement that prices would likely be higher but let's move on.

A. And I think I explained what I intended with that statement.

MR. DODGE: Let's move on.

THE HEARING OFFICER: Mr. Dodge?

MR. DODGE: Yes.

THE HEARING OFFICER: I might suggest this might be a good time for a break.

MR. DODGE: I'm down to one last couple of questions if you would indulge me for just a minute.

THE HEARING OFFICER: Sure.

MR. DODGE: But I'm happy to break if you'd rather.

THE HEARING OFFICER: If you have one or two questions, then it's probably best to keep going.

MR. DODGE: It's the last area.

THE HEARING OFFICER: Okay.

BY MR. DODGE:

Q. Mr. Peterson, you testified at some length

about the Idaho order that reduced PPA terms to two years; right?

A. I think I wrote a paragraph in my direct.

Q. And I assume you viewed that as relevant to the Commission, let's see what the Idaho Commission did?

A. Yes.

Q. Did you also review the Oregon staff testimony on this exact same issue where PacifiCorp is asking to reduce the PPA term in Oregon?

A. No.

Q. Are you aware they opposed the reduction for basically all the same reasons that my Coalition is opposing it?

A. Well, since I didn't read it, again, I'm not aware of it.

MR. DODGE: Thank you. No further questions.

THE HEARING OFFICER: Okay. Thank you. Why don't we recess until 1:30 by that clock. Thank you.

(Lunch recess 12:25 p.m. to 1:35 p.m.)

THE HEARING OFFICER: Okay. I think we're back on. Mr. Peterson, you're still under oath. And I think we're ready to move to Mr. Sanger; correct?

CROSS-EXAMINATION

BY MR. SANGER:

Q. Good afternoon, Mr. Peterson.

A. Hello.

Q. I'm not intimidating. I'm not Mr. Dodge. I wanted to ask you some questions about your earlier testimony about the Washington QFs.

So, can you refresh for all of us what your testimony was on those?

A. Essentially, the testimony is is that I asked data requests of the Company regarding Washington QFs. They responded that they have three contracts.

My understanding is, at least for small QFs, Washington has a five-year term limit on contracts and the Company responded that they have three PPAs that are within that five-year limit.

Q. And did you investigate when those PPAs were built or constructed?

A. No, I didn't.

MR. SANGER: May I approach the witness?

THE HEARING OFFICER: Yes.

MR. SANGER:

BY MR. SANGER:

Q. (Document distribution) So, my client is the Renewable Energy Coalition who is a party in this proceeding; correct?

A. That's my understanding.

(REC Exhibit-1 identified)

BY MR. SANGER:

Q. So, the Renewable Energy Coalition submitted testimony in a Washington avoided cost case earlier this year. And two of the Coalition members or one of the coalition's members is Yakima Tieton Irritation District described on page two of the Declaration of John Lowe which is page five in terms of page numbers, in terms of numbers of actual pages, but it's page two of 13, the Declaration of John Lowe.

And I've highlighted in the middle of the sentence there that Yakima Tieton is a Coalition member and they sell their power to PacifiCorp from two one-and-a-half megawatt hydroelectric projects and these facilities have been operating since 1986.

Do you have any reason to contradict that?

A. No.

Q. If you could turn to the next page of this. And it's page three of the Declaration of John Lowe. And there's a sentence in paragraph seven which states that: "The Deruyter Dairy methane facility is the only

Washington QF that has been built in and currently selling power to PacifiCorp since 1990."

Did you inquire into when this project was constructed or built?

A. So, you're looking at paragraph seven?

Q. Yeah. Paragraph seven, the third sentence. It's talking about the third QF project that's in Washington.

A. Okay.

Q. The dairy methane facility, it was constructed in 1990?

A. Well, in answer to your question which I believe was, did I inquire into that? The answer is no.

Q. Okay. Are you aware that the Washington Commission adopted five-year contract terms sometime after 1990?

A. I'm not familiar when they adopted that.

Q. So, you're not aware that there have been no Washington QFs that have been built recently under the five-year contract term?

A. I'm not aware one way or the other.

Q. Okay. And are you aware that the four operating megawatts of Washington QFs represents less than 0.3 percent of PacifiCorp's total megawatts of QFs on its system?

A. I see that's what it says there, but otherwise, I'm not aware of that.

Q. Okay. So, in terms of pointing to contracts or QFs that might be able to operate under a five-year

contract, these projects may not be ones that would support your assertion that QFs can operate under five-year contracts or be financed under five-year contracts?

A. Well, obviously they're operating under five-year contracts. The question of whether they can be constructed or not, I don't have an opinion about these particular contracts. I merely asked a data request of PacifiCorp and reported what the response was.

Q. Right. But you used that information in the portion of your testimony supporting the view that projects can obtain financing in order to develop with five-year contract terms; correct?

A. I think that's a fair characterization. It was to obtain evidence of five-year contracts. And I knew that PacifiCorp or that Washington, rather, had this limitation. And PacifiCorp represented that they had projects that were operating under those terms.

Q. But you did not investigate as to whether those projects were constructed with five-year contracts, only that they could continue to operate under five-year contracts?

A. As I said earlier, I did not investigate further.

Q. Okay. Thank you. Can you please refer to your

direct testimony on page twelve?

A.   Unfortunately, during the break ...

Which page?

Q.   Page twelve. Sorry about that.

A.   Okay. I have page twelve.

Q.   So, in the first full Q and A in the first full paragraph, there's the last sentence there. It reads -- well, could you read that last sentence that starts with the word, "Similarly"?

A.   "Similarly, QF developments funded by municipalities will probably not be affected since they are doing QF projects presumably as a matter of the municipalities' public policy and without profit motive."

Q.   Have you been able to identify any Utah municipalities or other nonprofits that have been able or I guess any municipalities or nonprofits that have been able to develop under five-year contract terms?

A.   I haven't specifically investigated that. So, the answer is no.

Q.   Did you inquire to potential municipalities that might want to the develop QF projects as to whether they can obtain financing?

A.   I did not specifically investigate that.

Q.   Are you aware that Mr. Nathan Rich who is a

Coalition member submitted testimony on behalf of Wasatch Integrated Waste Management?

A. I've seen his testimony, yes.

Q. And that's a waste management entity that's a nonprofit; correct?

A. That would be my understanding.

Q. And are you aware that he testified that his waste management service district would need to obtain financing and that under short-term contracts they could not obtain financing to develop the QF project?

A. Well, you'd have to show me specifically. I remember him saying something to that effect.

Q. Do you have any information to contradict Mr. Rich's testimony?

A. No.

MR. SANGER: Okay. I have no further questions.

THE HEARING OFFICER: Thank you.

Mr. Jetter, any redirect?

MR. SANGER: Your Honor?

THE HEARING OFFICER: Yes.

MR. SANGER: Can I move for the admission of the exhibit that I crossed Mr. Peterson on?

THE HEARING OFFICER: Sure. If any party objects to that, please indicate.

MR. JETTER: I would just raise an objection that if it's entered to establish the facts that are referenced therein because we have no -- I have no knowledge of whether those facts or accurate or not. I've never seen this document before.

And so, I'm troubled by entering this into the record in its entirety especially for anything that might be in there that I don't believe most of the parties here have had an opportunity to vet in any way.

THE HEARING OFFICER: Mr. Sanger, do you have any response to that concern?

MR. SANGER: Yes, your Honor. Mr. Peterson directly testified on this issue. This is a publicly-available document in another jurisdiction.

If necessary, Mr. John Lowe who submitted this testimony is in the chamber today and he's scheduled to testify. I could have him verify the truth and authenticity of this document as well.

THE HEARING OFFICER: Does any other party have any comment on this motion?

MR. JETTER: What I'd like to ask, maybe a question if this is the case. Mine also came with testimony of Higgins attached to the back.

MR. SANGER: We can remove the last part, the testimony of Mr. Higgins if that's a concern.

MR. JETTER: I think it would be appropriate to do that also if there's no other reason to enter that into the record.

THE HEARING OFFICER: Mr. Jetter, you're still maintaining your objection to the entry of Mr. Lowe's testimony?

MR. JETTER: I think at this point, yes, without some authenticity or authentication of it.

THE HEARING OFFICER: Okay. Let me ask you, Mr. Sanger. We have Mr. Peterson's testimony on the record with respect to this issue, but you still would like to enter the entire testimony into evidence?

MR. SANGER: I would like to enter the portions that I cross-examined Mr. Peterson on. I'm happy to reduce the length of it so that the whole document does not come into the record, but the portions that he -- I cross-examined him on, I would like to have that in the record.

THE HEARING OFFICER: So, you're speaking of just that -- well, paragraph four and paragraph seven?

MR. SANGER: Well, I would move for the admission of up to page four because the rest of those paragraphs in that section add light to that information. But starting on page four, there's a new section.

So, I would move for the admission of the first four pages of the declaration.

THE HEARING OFFICER: Okay. I think we'll allow this to be admitted. And again, we recognize that it doesn't have the same weight as other testimony. It's from a separate docket. And we also have Mr. Peterson's testimony on the stand that pretty much establishes his position on the issues in these. So we'll allow that. Thank you.

(REC Exhibit-1 Admitted)

MR. SANGER: Thank you.

THE HEARING OFFICER: Anything else, Mr. Sanger?

MR. SANGER: No, your Honor. Thank you.

THE HEARING OFFICER: Back to Mr. Jetter for redirect.

MR. JETTER: I have no redirect for Mr. Peterson. He's available for questions from the Commission.

THE HEARING OFFICER: Okay.

Commissioner White?

COMMISSIONER WHITE: I have no questions, Chair.

THE HEARING OFFICER: Commissioner Clark?

COMMISSIONER CLARK: No questions.

THE HEARING OFFICER: And I have none.

Thank you.

MR. PETERSON: Thank you.

THE HEARING OFFICER: Mr. Jetter?

MR. JETTER: Thank you. Charles Peterson is the Division's only witness. And that is I guess the conclusion of our evidence we are going to present today. Thank you.

THE HEARING OFFICER: Okay. Thank you. And I think at this point Mr. Sanger had contacted our office with a witness availability issue.

So, why don't I let you address that at this point and see where we should go with that.

MR. SANGER: Thank you. I have two witnesses, Mr. John Lowe and Mr. Nathan Rich. I contacted the Commission about the availability of Mr. John Lowe, that I would strongly prefer to have him on the witness stand today. Mr. Nathan Rich has subsequently informed me that he has scheduling issues and would also like to get on the stand today.

So, I would like to at some point schedule time so that we can have them testify potentially the first of the intervenors so we can get them on the stand today.

THE HEARING OFFICER: Okay.

Does anyone have any comments or concerns with that request? And it probably doesn't matter whether we go before or after the Office. The Office and the remaining intervenors all have similar positions.

Would there be any rejection to going to those two first and then moving on with the Office?

MR. JETTER: No.

MR. MOORE: No objection.

THE HEARING OFFICER: Any other objection? Why don't we go that way. So, Mr. Sanger, why don't you go ahead with your first witness.

MR. SANGER: Thank you very much. I call Mr. John Lowe to the witness stand.

THE HEARING OFFICER: Mr. Lowe, do you swear to tell the truth?

THE WITNESS: I do.

JOHN LOWE,

having first been duly sworn, was

examined and testified as follows:

DIRECT EXAMINATION

BY MR. SANGER:

Q. Mr. Lowe, did you prepare or have prepared on your behalf testimony of Mr. John Lowe on behalf of the Renewable Energy Coalition?

A. Yes.

Q. Do you have any corrections at this time to your testimony?

A. No.

Q. If you were asked the same questions today, would your answers be the same?

A. Yes, they would.

MR. SANGER: I respectfully move for the admission of the testimony of Mr. John Lowe.

THE HEARING OFFICER: If any party objects, please indicate. Seeing none, they will be entered.

(REC Testimony of John Lowe Admitted)

BY MR. SANGER:

Q. Mr. Lowe, do you have a short statement prepared?

A. A few comments. I don't know that it's much of a preparation. First of all, let me tell everyone of the Commission what REC is.

We are a Coalition of renewable energy projects which are all base load in nature and all small, less than ten megawatts except one which is 32 megawatts in size. And except for two projects which is the biomass project I just mentioned which is in Oregon and Nathan Rich's Wasatch project here in Utah, all of the other projects which are close to 50 in the Northwest states; Oregon, Idaho, Washington, Utah, Montana and Wyoming, about 50 projects are included. So, I think about 48 of those are hydroelectric projects.

The other thing about these projects is that they are all existing projects unlike a lot of the conversation that takes place is in the context of new projects. The coalition's main interest, not exclusive, but main interest is in protecting the interests and balancing the interests of these existing projects in that they would require new power purchase agreements or replacement agreements, whatever you want to refer to them as, interconnection agreements, so forth, as the projects mature and continue on.

And in addition to that, these projects will likely require additional capital to make improvements, repairs, replacements, efficiency changes, interconnection redos, et cetera, et cetera.

So, our concern is with these types of projects and that fact that they will in fact need contracts that are in excess of three years in order to meet their needs similar to new projects.

The other concern that we have in this proceeding has to do with the capacity issue. And we're very concerned about existing projects that have been paid capacity and typically treated as part of the resource stack and the utility's IRP may not get capacity payments. And if the sufficiency period is always in excess of the contract term, it's highly improbable they would get capacity payments under the concepts that are going forward. So, we're very concerned about that.

And the last thing I would mention is regarding some of the points that were discussed in the state of Washington because one of the projects that was being discussed as a member of the Coalition in the form of Yakima Tieton Irritation District.

And in my former role at 26 years dealing with PURPA issues for PacifiCorp, I have a long and deep history with that particular entity, those two projects as well as the third project that was referred to in the previous conversation were projects that were all built under long-term contracts that existed and were allowable in the state of Washington.

That was subsequently replaced by the five-year contract term. And so, these projects are under short-term contracts, but in no way were they ever built or financed under short-term contracts.

I think that's really all I have to say to summarize our testimony and position.

THE HEARING OFFICER: Okay. Thank you.

Anything further, Mr. Sanger, of this witness?

MR. SANGER: No. Thank you.

THE HEARING OFFICER: Ms. Dutton, any cross-examination?

MS. DUTTON: No. Thank you.
THE HEARING OFFICER: Thank you. Mr. Ritchie?
MR. RITCHIE: No cross.
THE HEARING OFFICER: Mr. Dodge?
MR. DODGE: No. Thank you.
THE HEARING OFFICER: Mr. Moore?
MR. MOORE: No. Thank you.
THE HEARING OFFICER: Mr. Jetter?
MR. JETTER: I have no questions. Thank you.
THE HEARING OFFICER: Thank you. Ms. Hogle?
MS. HOGLE: I have no questions.
THE HEARING OFFICER: Okay. Thank you, Mr. Lowe. Commissioner White, do you have any questions?
COMMISSIONER WHITE: I have no questions. Thanks.
THE HEARING OFFICER: Commissioner Clark?
COMMISSIONER CLARK: It's unanimous.
THE HEARING OFFICER: Mr. Sanger?
MR. SANGER: I would call to the witness stand Mr. Nathan Rich.
THE HEARING OFFICER: Mr. Rich, do you swear to tell the truth?
THE WITNESS: I do.
(REC Rebuttal Testimony of Nathan Rich identified)

NATHAN RICH,
having first been duly sworn, was
examined and testified as follows:

DIRECT EXAMINATION

BY MR. SANGER:

Q. Mr. Rich, did you prepare or have prepared on your behalf rebuttal testimony of Mr. Nathan Rich on behalf of the Renewable Energy Coalition?

A. I did.

Q. Do you have any corrections to that testimony at this time?

A. No.

Q. If I asked you the same questions here today, would your answers be the same?

A. Yes, they would.

MR. SANGER: I respectfully move for the admission of Mr. Nathan Rich.

THE HEARING OFFICER: If any party objects, please indicate. Seeing no indication, it will be entered. Thank you.

(REC Rebuttal Testimony of Nathan Rich Admitted)

MR. SANGER: I tender Mr. Rich for cross-examination. And I believe he has a short statement to start the process.

THE HEARING OFFICER: Okay. We'll start with the statement.

MR. RICH: Thank you. I appreciate the opportunity to be heard by the Commission. You have my testimony. I won't spend a great deal of time going back over that. But I think it's important and I understand the concern that 2,000 megawatts of new QF power would cause a problem to the Company.

But I think we need to be careful about unintended consequences and I think our projects speak directly to that. We have two projects just to clarify a little bit some of the earlier testimony.

When our facility was built -- and it's a municipal waste combustion facility. So, we generate -- primarily our business is to generate renewable steam which we sell to Hill Air Force Base and they use that generally as heating on the other side of the base.

So, as part of the construction of the facility, it was constructed with 1.6 megawatt back-pressure turbine.

So, we take the high-pressure steam down through our turbine. The turbine is there to operate the facility. It was put there to operate the facility.

We made an interconnection to the utility in the 1993 time frame. And that was our original power purchase agreement was actually an open ended year-to-year agreement.

We were approached by PacifiCorp two or three years ago and they were cleaning up their old contracts. They wanted to enter into a new contract. Hence, our current 11-year power purchase agreement. The reason that that's an 11-year agreement is because that matches the timeframe of our current contract with Hill Air Force Base for the sale of steam. So, we didn't want to firm up our power beyond that.

And to put this into perspective, we sell between five and $6 million worth of steam to Hill Air Force Base in a year, and we're currently generating revenues of 30 to $40,000 on our power purchase agreement with PacifiCorp. So, it was really not the driving factor. And that turbine is there to power the facility.

The second project, and this is really why I felt it was important to be heard on the issue, Hill Air Force Base uses 100 percent of our steam during the winter months. So, in the summer months --

And we generate typically about 100,000 pounds per hour of steam. In the summer months, they are not able to use our full load and we've looked a number of times at adding additional generation capacity to capture that unused summer steam. And we've been through several engineering cycles on that project.

Most recently, in fact, PacifiCorp just completed the first part of an interconnection study to help us understand our interconnection cost for that program. It's about a $10 million project. It's not something that we currently have equity on hand to finance. We're old school. We would finance that project typically through a revenue bond.

So, right now we're trying to understand whether that project actually has economic viability, but without the ability to contract at least for the period that might represent a simple payback on the project is not something, number one, that I believe we would be able to receive favorable terms on financing.

And beyond that, it wouldn't be something that I would probably be able to convince our board that would make good sense if we couldn't find the financing at least to cover us during the payback period in that project.

So, you have my testimony. And if there's anything additional you'd like to add, that would be great. Thank you.

MR. SANGER: I have nothing further.

THE HEARING OFFICER: Okay.

Ms. Dutton, any questions?

MS. DUTTON: No. Thank you.

THE HEARING OFFICER: Thank you. Mr. Ritchie?

MR. RITCHIE: No. Thank you.

THE HEARING OFFICER: Mr. Dodge?

MR. DODGE: No.

THE HEARING OFFICER: Mr. Moore?

MR. MOORE: No.

THE HEARING OFFICER: Mr. Jetter?

CROSS-EXAMINATION

BY MR. JETTER:

Q. I do have a few questions. Good afternoon.

In your brief statement that you've just discussed, did I understand you correctly that the current project that you have, the first one, was built and financed with year-to-year contracts with Rocky Mountain Power?

A. It was built and financed as part of a $54 million bond issue in 1987 because that turbine is part of the physical operation of the plant.

The primary reason for the 1.6 megawatt turbine is to power the plant. Frankly, selling the power to Rocky Mountain Power is an afterthought and that interconnection was added seven years later.

So, we're generating 1.6 megawatts and we're selling, it's up and down, but typically three to 400 kilowatts is all that we're selling to PacifiCorp.

So, the contract is to help us continue with the ongoing maintenance and operation of the facility.

Q. Okay. And with respect to the current facility, the term of the contract was immaterial to whether it was built or not; is that correct?

A. Absolutely because the project is a municipal waste incinerator selling steam to Hill Air Force Base, and the term of the contract with Hill Air Force Base as the major power off-take of the project was critical and that was also an open-ended contract with Hill Air Force Base at the time.

So, that's the contract that -- it's hard to draw the parallel between our small electric contract and the real power purchase agreement that built the facility is the sale of steam to Hill Air Force Base.

Q. Thank you. With respect to the second project, the desire to add an additional turbine is my understanding; is that correct?

A. That's correct.

Q. What is the payback period for that?

A. Well, it depends on the power off-taker and how much they're willing to pay for the power. Using current Schedule 37 -- and in -- the project actually would deliver about five and a half megawatts of power to the grid. So, Schedule 37 doesn't strictly apply.

But using Schedule 37 as a best case, the project is about a $10 million project. And because the power is seasonal -- and that's one thing that makes it hard. The steam is worth much more than the electricity. So, in the winter we sell steam and then in the shoulder months, we would start to ramp all the electricity and then its base load power through the summer season. The current simple payback on that scenario selling to PacifiCorp under Schedule 37 is about 24 years.

Q. And so, your testimony earlier, even in a 20-year term, you don't think that you could finance that or convince your board because you wouldn't have a contract, then, throughout that period?

A. Oh, I think a 20, with the possibility of a 20-year agreement would give me hope that we could work toward finding a power off-taker or having actual conversations which would be required contract negotiations under Schedule 38.

But it's a tough project, absolutely. But a three-year contract slams the door.

Q. Okay. But a three-year contract on your first project wouldn't have mattered. That would have actually been three times as long as your --

A. Because the first project was a waste energy project selling steam to Hill Air Force Base. You can't look at that as an electrical contract. In fact, the interconnection to the utility wasn't made until the facility had been on line for five years.

MR. JETTER: Okay. That's all the questions I have. Thank you.

THE HEARING OFFICER: Thank you. Ms. Hogle?

MS. HOGLE: I have no questions.

THE HEARING OFFICER: Do you have any redirect, Mr. Sanger?

REDIRECT EXAMINATION

BY MR. SANGER:

Q. Yes, Your Honor. One question.

Just to clarify, your existing project, it was not built as a qualifying facility project designed to sell electricity. It wasn't your intention in the reason that you sold it because you didn't start selling it until seven years after?

A. That is correct.

Q. And could you have financed that under a three-year financing arrangement?

A. Well, no. And again, you know, the original bond issue on the waste energy facility was a 20 -- was financed several times, but I believe a 25-year bond issue for the original facility which included the generation capacity that's currently on line.

MR. SANGER: No further questions.

THE HEARING OFFICER: Thank you. Any recross?

If anyone wants recross, let me know.

(No response) Okay. Thank you. Mr. Sanger, anything else? Oh, I'm sorry. I forgot.

Commissioner White, do you have any questions?

COMMISSIONER WHITE: I have no questions. Thank you, Chair.

THE HEARING OFFICER: Mr. Clark?

COMMISSIONER CLARK: I don't have any.

THE HEARING OFFICER: I don't have any either. Thank you.

MR. SANGER: Your Honor, may I excuse Mr. Rich and Mr. Lowe for the rest of the hearing or at least from participation tomorrow?

THE HEARING OFFICER: Is there any objection from any party? (No response). Certainly. Thank you.

MR. SANGER: Thank you.

THE HEARING OFFICER: Anything else from you, Mr. Sanger?

MR. SANGER: No, your Honor. Thank you.

THE HEARING OFFICER: Okay. Thank you.

Mr. Moore?

MR. JETTER: The Office calls Bella Vastag.

THE HEARING OFFICER: Do you swear to tell the truth?

THE WITNESS: Yes, I do.

THE HEARING OFFICER: Thank you.

BELA VASTAG,

having first been duly sworn, was

examined and testified as follows:

DIRECT EXAMINATION

BY MR. MOORE:

Q.   Could you state and spell your name and occupation for the record?

A.   Yes. My name is Bela, B-e-l-a, Vastag, V-a-s-t-a-g. I'm a utility analyst employed by the Office of Consumer Services.

Q.   Have you reviewed the Company's application in this case?

A.   Yes, I have.

(Direct, Rebuttal, and Surrebuttal Testimony of Bela Vastag identified)

BY MR. MOORE:

Q.   Have you prepared direct, rebuttal, and surrebuttal testimony?

A.   Yes.

Q.   Do you have any corrections to that testimony?

A. No corrections.

Q. If I were to examine you and ask you the questions in your testimony, would your answers be the same?

A. Yes.

MR. MOORE: The Office would move for admission of his testimony.

THE HEARING OFFICER: If any party objects, please indicate. Seeing none, thank you. It'll be entered.

(Direct, Rebuttal, and Surrebuttal Testimony of Bela Vastag Admitted)

BY MR. MOORE:

Q. Have you prepared a statement summarizing your testimony?

A. Yes. I have a brief statement.

Good afternoon. Federal and state laws have been enacted to encourage the development of small power producers such as qualifying facilities or QFs.

The Company proposes in this docket to limit the maximum contract length for a QF's power purchase agreement or PPA to three years.

The Office believes that this would be an unnecessary barrier against QFs and would discourage the development of these small power producers contrary to the intent of laws to promote their development.

Therefore, the Office opposes the Company's request and recommends that the maximum PPA contract length remain at 20 years.

The Office also opposes some parties' proposals that the calculation of the compensation for capacity value in a QF contract be based on a longer term than the term of the PPA.

If this method was adopted and such a PPA was not renewed at the end of its term, then ratepayers would have paid for capacity that was never delivered which would violate the PURPA standard of ratepayer indifference. The Commission should reject a capacity value calculation that goes beyond the term of a QF's PPA.

The Office does agree with some of the concerns that the Company and the Division have raised with acquiring a large amount of power from QFs.

These concerns include, A, resource acquisition being done outside of the Company's system-wide Integrated Resource Plan or IRP evaluation and planning process;

B, an increased risk to ratepayers with carrying large amounts of long-term fixed-price contracts for power. The direction of power prices in the future is uncertain. And unlike a company-owned resource, QFs cannot be economically dispatched to take advantage of periods when low-priced market purchases of power are available.

The office believes that the best remedy for these concerns is the use in QF PPAs of avoided cost pricing that is properly modeled, accurately calculated, and timely updated. We request that the Commission always insist on continual diligence and rigor in establishing avoided cost prices under Schedule 37 and Schedule 38. And that concludes my statement.

THE HEARING OFFICER: Anything else, Mr. Moore?

MR. JETTER: No, sir.

THE HEARING OFFICER: Okay. Thank you.

Ms. Dutton, any cross-examination?

MS. DUTTON: No. Thank you.

THE HEARING OFFICER: Mr. Ritchie?

MR. RITCHIE: No cross.

THE HEARING OFFICER: Mr. Dodge?

MR. DODGE: No. I have no questions. Thanks.

THE HEARING OFFICER: Thank you. Mr. Sanger?

MR. SANGER: No questions.

THE HEARING OFFICER: Mr. Jetter?

MR. JETTER: I have no questions.

THE HEARING OFFICER: Ms. Hogle?

MS. HOGLE: A few.

THE HEARING OFFICER: Thank you.

CROSS-EXAMINATION

BY MS. HOGLE:

Q. Good afternoon, Mr. Vastag.

A. Good afternoon.

Q. To your knowledge, was the OCS a participant in the hedging collaboratives?

A. To my knowledge, yes.

Q. And is it your understanding and, more importantly, the OCS's understanding that the principles and guidelines that were entered into the record as I believe Cross Exhibit-2 for the Coalition applied to both gas and electricity hedges?

A. I was not involved in that docket. So, I'm not sure if that's correct.

Q. Okay. But as a representative of the OCS, is it true that the OCS supports the principles and guidelines that resulted from that hedging collaborative?

A. Yes. It's safe to say we were supportive of the results.

Q. Okay. Did you read Mr. Higgins' and Ms. Ferk's testimony in this case?

A. Yes.

Q. And would you agree with me that both of them

being a 20-year PPA, a QF PPA has a risk mitigation or reduction of potential 111(d) requirements?

A. I would agree with that, yes.

Q. Okay. You participated in the avoided cost Docket Number 12-035-100 where the current avoided cost methodology was approved; is that correct?

A. That's correct.

Q. And one of the issues in that case was whether the RECs would stay with the developer or with the Company in the PPA transaction; right?

A. Yes.

Q. And do you recall what the Commission's decision was on that issue in that case?

A. Yes, I do.

Q. So, you would agree with me that the Commission decided that the RECs would be retained by the QF absent an expressed negotiation for additional compensation for those RECs; is that correct?

A. That's correct.

Q. And so, would you also agree with me that a 20-year PPA under current law would not, in fact, mitigate any potential 111(d) requirements for the Company?

A. That is uncertain whether or not the REC issue would affect compliance but it is an issue.

Q. Okay. I'd like you to turn to your direct testimony if you will, please, specifically page three. And actually, I believe that you said this in your summary. So, at line A-1 you state that it is extremely important that avoided cost modeling be rigorously and maintained and updated; is that correct?

A. Correct. Uh-huh (affirmative).

Q. And you would agree with me that current avoided cost prices reflect current or near term conditions?

A. Well, they're calculated using current data --

Q. Okay.

A. -- but they reflect a 20-year time period.

Q. Okay. So, would you agree with me that it's much easier to forecast prices two to three years out as compared to 20 years out?

A. It's probably easier to do a shorter term forecast.

Q. Okay. And so, isn't it true that all long-run estimates, no matter how rigorous of avoided costs will be prone to forecast inaccuracies?

A. Yes. And I admitted in my surrebuttal that forecast error is an issue, but there are other issues with inaccurate avoided cost calculations, not just forecasting of future prices.

MS. HOGLE: Okay. Thank you. That's all I have.

THE HEARING OFFICER: Mr. Moore, any redirect?

MR. MOORE: No redirect, sir.

THE HEARING OFFICER: Okay. Thank you.

Commissioner White?

COMMISSIONER WHITE: No questions. Thank you.

THE HEARING OFFICER: Commissioner Clark?

COMMISSIONER CLARK: Thank you. I have no questions.

THE HEARING OFFICER: I have none. Thank you, Mr. Vastag. Anything further, Mr. Moore?

MR. MOORE: Nothing further.

THE HEARING OFFICER: We'll go to Ms. Dutton next.

MS. DUTTON: Thank you. Utah Clean Energy calls Ms. Sarah Wright.

THE HEARING OFFICER: Do you swear to tell the truth?

THE WITNESS: I do. Good afternoon and thank you.

SARAH WRIGHT,

having first been duly sworn, was

examined and testified as follows:

DIRECT EXAMINATION

BY MS. DUTTON:

Q. Please state your name, position, and business address for the record.

A. My name is Sarah Wright and my business is Utah Clean Energy. We're a nonprofit incorporation. And the address is 1014 Second Avenue, Salt Lake City, Utah 84103.

Q. Have you reviewed the Company's application in this case?

A. Yes, I have.

(UCE Exhibit-1 and Exhibit-2 identified)

BY MS. DUTTON:

Q. And did you submit direct and surrebuttal testimony in this docket marked as UCE Exhibits 1 and 2?

A. Yes, I did.

Q. Do you have any changes or corrections to make to your written testimony?

A. No, I don't.

Q. If I asked you the same questions today as are set forth in your written testimony, would your answers be the same?

A. Yes, they would.

MS. DUTTON: Thank you. Utah Clean Energy moves to enter Ms. Wright's direct and surrebuttal testimony into the record.

THE HEARING OFFICER: Okay. If anyone objects, please indicate. Seeing none, that will be entered. Thank you.

(UCE Exhibit-1 and Exhibit-2 Admitted)

BY MS. DUTTON:

Q. Did you prepare a summary of your written testimony to share with the Commission today?

A. Yes, I did.

Q. Please proceed.

A. As most of you know, Utah Clean Energy strives to create safer, more efficient, cleaner, and a smarter energy future. And the Public Utility Regulatory Policy Act, PURPA, is an important mechanism for influencing renewable energy development in Utah and diversification of our energy supply.

It is in the best interest of ratepayers to safeguard the proper implementation of PURPA.

Rocky Mountain Power's proposal to reduce the contract term to three years undermines PURPA and the state policy by effectively making these projects extremely expensive, extremely difficult, if not possible to finance.

It would ensure that projects will not be built and it would therefore allow the utility to circumvent PURPA and prevent ratepayers from benefiting from

QF resources.

In the Company's testimony, they incorrectly compared QFs to hedging practices. Renewable QF projects are clearly not economic hedges and it is incorrect to apply the Company's hedging and trading practices to QF projects. QF projects are steel in the ground resources that provide a capacity value to the system and this value is significant.

In contrast, hedging projects do not provide the ratepayers with a long-term capacity value.

And finally, further -- not finally, but finally for this section, a QF project is not a commodity hedge just because it provides incidental but significant risk mitigating benefits to ratepayers.

So, now we move to risk and protection from risk. Of course we know and it's been discussed quite a bit today that there is always risk associated with all resource decisions including short-term decisions.

And FERC contemplated that prices would go up and down and that this reality would be borne both ways. The presence of risk does not alleviate the Utah Public Service Commission of its duty to implement the policies and requirements of PURPA and Utah statute which states that it is the policy of this state to encourage the development of independent and qualifying power production and cogeneration facilities to produce a diverse array of economical and permanently sustainable resources in an environmentally acceptable manner.

QF projects do provide ratepayers with additional value by protecting ratepayers over the 20-year contract for risk associated with fuel volatility, unanticipated O and M costs, environmental cost, and environmental compliance cost. And I'm happy to address some of the issues around the clean power plan.

Regardless of REC ownership, these projects will reduce the Company's emissions. And in the long run, the lower emissions that we have, especially if the state chooses to go with a mass-based profile, it will help with compliance. The exact mechanisms of how the clean power plan will operate we don't know yet or how Utah will implement it.

But there are benefits to reduced carbon emissions, risk-mitigating benefits regardless of whether you own the RECs. And you have, as I understand, at least for about 300 megawatts of the projects negotiated ownership of the RECs.

On contrast, company-owned resources and market purchases do not provide the protection from these risks.

In fact, the Company has an energy cost

adjustment mechanism that they can use to recoup costs if the future unfolds in a way that's different when they planned their resources. They can recoup costs for planned O and M expenses and other environmental upgrades.

QF procurement is definitely aligned with the Company's Integrated Resource Plan. Because the PDRR avoided cost pricing method is directly tied to the resources that are identified in the company's least-cost least-risk portfolio and the type and timing of those resources identified in their least-cost least-risk portfolio, to the extent the capacity is not needed until a date into the future or if there are a number of QFs ahead of this resource in the queue, the pricing is reduced. The avoided cost pricing method is an iterative and dynamic tool that was approved by the Commission to align with the IRP and to meet the ratepayer indifference standard.

The final point I'd like to make is that the 20-year contract term allows viable QF projects to secure financing. And this pricing method, the avoided cost pricing method, is what ensures the ratepayer indifference standard is protected and only viable projects that meet the ratepayer indifference standard will be built.

The Commission approved avoided cost method is the mechanism that the Commission approved to ensure that rates are just and reasonable to ratepayers and nondiscriminatory to QFs consistent to the requirements of the PURPA and state statute.

Both those requirements are equally important. The pricing method was built on the assumption of a QF that the QF may contract for 20 years.

The Commission's role based on PURPA and state policy is to encourage the development of QF resources while ensuring rates are just and reasonable to ratepayers and nondiscriminatory to QFs.

The current QF avoided cost method with a 20-year contract will do just that. While a change to a three-year contract would circumvent the intent of PURPA and state statute and deny ratepayers the benefits of QFs. I recommend that the Public Service Commission deny the Company's application to reduce the contract term. Thank you.

THE HEARING OFFICER: Anything else, Ms. Dutton?

MS. DUTTON: No. Ms. Wright is available for cross-examination.

THE HEARING OFFICER: Thank you.

Mr. Ritchie, any questions?

MR. RITCHIE: No questions. Thank you.
THE HEARING OFFICER: Mr. Dodge?
MR. DODGE: No questions.
THE HEARING OFFICER: Mr. Sanger?
MR. SANGER: No questions.
THE HEARING OFFICER: Mr. Moore?
MR. MOORE: No questions. Thank you.
THE HEARING OFFICER: Mr. Jetter?

CROSS-EXAMINATION

BY MR. JETTER:

Q.   I do have a few questions.

A.   Hello, Mr. Jetter.

Q.   Good afternoon, Ms. Wright. You testified I believe both in direct and in your surrebuttal testimony that shortening the term of these contracts would make them difficult, if not impossible to finance; is that correct?

A.   Yes.

Q.   And the reason for that, is it correct, that the lenders, the market providing the financing, is unwilling to take the risk of variation in price into the future; is that correct?

A.   They are unwilling to take the risk to build a project that doesn't have a long-term off-taker.

Q.   And do you believe that shortening the term

of the contract changes the obligation to purchase that energy in periods into the future?

A. So, I guess maybe I will amend my first answer that it's the off-taker and it's the price. They have to know that that project is financeable and that they are going to recoup enough through sales to finance and pay for the project.

Q. Okay. And you testified that you believe that the current future projections have significantly greater risk. And let me clarify this. Current future forecasts for energy prices you think have greater upside risk.

And by that, I mean it's more likely than not they will be higher than we predict rather than lower than we predict; is that correct?

A. I tried to clarify that in my surrebuttal. I talked a lot about asymmetrical risk. So, you can think of -- so, today prices are about $3 or whatever they are a megawatt hour, I mean, $30 a megawatt hour.

And so, and most of that is fuel cost, and that price is bound by zero but it's actually bound by more than that because you have to develop those risk.

So, those prices, it's asymmetrical. The magnitude that we can go lower is much smaller than the magnitude that we can go higher.

Any of us that were here in the year 2000 know that prices could be much higher. Plus, there are many environmental regs coming down. So, yes, the magnitude of risk is more, the magnitude that they can go up is much greater than what's bound by zero.

Q. Okay. And so, it would seem financially foolish, then, to enter into a long-term contract today when you have greater potential for higher energy prices in the future; is that correct?

A. No, because you have to -- you have to be able to build those and finance those projects. If you're a financier, you're not someone that plays in the energy markets. You want to know that you have a project that is financeable and that that is a locked in -- you know, that that project is going to go.

Q. And so, you would say, then, that the contract for the 20 years removing the risk of market fluctuations and energy prices has a significant value.

In fact, that value is so high that a project cannot be completed without it; is that correct?

A. Well, it depends on what you mean by value. It has a value to ratepayers, too because if we can lock in that price. The higher the risk, the higher the financing cost. And when you're dealing with a very capital-intensive project, those projects would then be much more expensive and then they would not be built to the benefit of ratepayers.

Q. And so, is it correct, then, that your testimony is that the risk has such a high cost I guess on the flip side of that, the risk has such a high cost that no lenders will lend on these projects?

A. Well, I think that the developers should speak more to that, but from seminars and research that I've done that -- well, just think about if you bought a house and the cost of financing.

If you had a very bad credit rating, it would cost you a lot more to finance that house over the term of the house over the 30-year mortgage than it would if you were, you know, an A-plus credit rating.

So, just, the higher the risk, the higher the cost to finance that project which makes them more expensive, which puts them out of the money for PURPA which circumvents PURPA.

Q. Okay. Let me use that analogy. If you have very bad credit -- and I believe your analogy is, in that, probably intermittent nature of these resources and the variability of market prices, you would probably seek a cosigner maybe with better credit; is that accurate?

A. I'm talking about the difference in pricing of financing. So, these projects, it's not that they're variable that's a problem. It's the fact that they need a long -- you know, you're buying 20 years of fuel up front when you build one of these projects. So, you need long-term financing.

Q. And you compared it to a person with bad credit; is that right?

A. No. I compared that with the risk is higher because you don't have a 20-year contract, then your interest rates and your finance costs will be higher.

Q. But if you could find somebody to take that risk for you, so, to guarantee those payments for 20 years, then you can get the financing; is that correct?

A. Meaning if you have an off-taker for your project?

Q. If you have any source of guaranteed funding for your project.

A. I think these questions would probably be best asked to the renewable energy developers. But what I'm saying is that the financiers, to give you good credit that keeps the cost down so these projects can be built within avoided cost pricing to the benefit ratepayers, especially, I mean you've heard UAE talk about how these projects are beneficial, you need low-cost financing. You need a long-term power purchase agreement.

Q. Okay. And so, the long-term financing is

conditioned upon the long-term -- excuse me.

The low-cost financing would be in your testimony conditioned upon long-term power purchase agreements?

A. That's my understanding from talking to developers.

Q. Okay. And that reduction in the cost of financing is due to somewhat other than the developer taking that risk, removing the risk that you're worried about in year-to-year or short-term contracts?

A. I think we're mixing different types of risks. The risk that I talk about with the asymmetrical risk in the project has to do with what's going to happen to ratepayers in the future.

And the risks that we're talking about regarding financing is the risk associated with investing millions of dollars in a project and being able to, as a financier, having the assurance that you will get paid back.

Q. And that's what I think I'm looking at here is the risk of the insurance you'd be paid back.

You need to put that risk on some other party in order to have these projects achieve low-cost financing; is that correct?

A. If you're trying to say that customers are bearing them? I mean, I'm not sure what you're getting at because they're two different types of risk, and if a long-term power purchase agreement, if it's your position that that's a risk at these low prices, then yes.

MR. JETTER: Thank you. I have no further questions. Thank you, Ms. Wright.

THE WITNESS: Thank you, Mr. Jetter.

THE HEARING OFFICER: Thank you. Ms. Hogle?

CROSS-EXAMINATION

BY MS. HOGLE:

Q. I have a few. Good afternoon.

A. Good afternoon, Ms. Hogle.

Q. Would you agree with me that some states have RPS requirements?

A. Yes.

Q. And that Utah has a renewable energy target for qualifying facilities?

A. It's actually a requirement, but the way that this document was written, it allows RECs from 1995 to qualify. It says that they're cost effective, we need to do it, but you guys have already complied because of the way that the statute was influenced when it was passed.

MS. HOGLE: Okay. May I approach the witness?

THE HEARING OFFICER: Yes.

BY MS. HOGLE:

Q. Okay. And you've already mentioned the cost effectiveness. So, can you read for me 54-17-602(a) where it starts, "Cost-effectiveness" under subsection one, it is determined?

A. Wait. 54-17-602(a), (1)(a)?

Q. 54-17-602(2)(a) --

A. Oh, (2)(a). "Cost-effectiveness under
Subsection (1) for other than a cooperative
association is determined in comparison to other
viable resource options using the criteria provided
by Subsection 54-17-201(2)(c)(ii)."
Do you want to let people know what I'm reading from?

Q. Well, I believe that I just mentioned --

A. Okay. So, this is Utah state statute?

Q. Yes. Utah state statute. So, if you flip to the next page that I handed to you?

A. Certainly.

Q. Can you read 54-17-201(2)(c)?

A. "In ruling on the request for approval of
a solicitation process, the commission shall
determine whether the solicitation process:" --

Q. And then can you skip to little numeral two?

A. "shall provide an opportunity for public
comment."

Q. "is in the public interest taking into

consideration:"

A. Wait. I read the wrong two? I did read the wrong two.

Q. Yes.

A. "is in the public interest taking into consideration: (A), whether it will most likely result in the acquisition, production and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state;"

Q. Continue.

A. "long-term and short-term impacts; (C) risk, (D) reliability; (E) financial impacts on the affected electrical utility; and (F), other factors determined by the commission to be relevant."

Q. Thank you. Okay. Can you now please go back to 54-17-602(3)(b). Can you start reading?

A. Wait, wait, wait. 602(3)?

Q. 602(3)(b).

A. Oh. I thought you said E.

Q. "This section does not require ..."

A. Oh, three.

Q. (3)(b). Excuse me.

A. "This section does not require an electrical corporation to: (b) enter into any additional electrical sales commitment or any other arrangement for the sale or other disposition of electricity that is not already, or would not be, entered into by the electrical corporation."

Q. "or"

A. "or (c) acquire qualifying electricity in excess of its adjusted retail electric sales."

Q. Okay. Thank you. So, is it a fair characterization of your testimony that avoided cost prices are very low right now?

A. Yes.

Q. Okay. And you would agree with me, would you not, that the Commission's decision in this case is not a short-term decision?

A. Yes.

Q. And that you have testified that avoided costs are, with your clarification today, more likely to go up and down from this point?

A. The magnitude.

Q. Okay. And so, you would agree with me that higher avoided cost pricing will make PPAs more attractive?

A. Yes, if all things are equal, if the extension of the ITC. There are a number of factors.

Q. And the higher avoided cost pricing for

20 years will make them even more attractive?

A. Yes.

MS. HOGLE: Okay. I have no further questions. Thank you.

THE HEARING OFFICER: Thank you.

Ms. Dutton, any redirect?

REDIRECT EXAMINATION

BY MS. DUTTON:

Q. Yes, please. Just a couple.

Does the fact that or the possibility that avoided cost prices could go up alleviate the Commission of its duty to implement PURPA?

A. No, it doesn't. And it also doesn't mean that they wouldn't be in the best interest of ratepayers.

Q. And in your analogy, you used two mortgages. You were comparing a bad credit rating to an inability to secure long-term financing; is that correct?

A. Yes, or to -- trying to finance something without a long-term purchase commitment.

Q. Yes. And one last question. Why is it a good idea to enter into QF contracts now?

A. You know, there are number of reasons. One is because, and I think it was brought up by the Office, is that renewable projects, solar projects in particular with the investment tax credit, these prices are likely as low as they're going to be for a while. 30 percent reduction in cost to Utah ratepayers for these projects from the investment tax credit.

MS. DUTTON: Thank you.

THE HEARING OFFICER: Thank you. Does any party desire recross? Seeing none, Commissioner White?

COMMISSIONER WHITE: I have no questions. Thank you.

THE HEARING OFFICER: Commissioner Clark?

COMMISSIONER CLARK: No questions. Thank you.

THE HEARING OFFICER: Thank you. I don't have any. Thank you, Ms. Wright.

THE WITNESS: Thank you.

Anything further, Ms. Dutton?

MS. DUTTON: No. Thank you.

THE HEARING OFFICER: Okay. Mr. Ritchie?

MR. RITCHIE: Sierra Club calls Mr. Thomas Beach, please.

THE HEARING OFFICER: Mr. Beach, do you swear to tell the truth?

THE WITNESS: I do.

THE HEARING OFFICER: Thank you.

R. THOMAS BEACH,

having first been duly sworn, was

examined and testified as follows:

DIRECT EXAMINATION
BY MR. RITCHIE:
Q. Can you make sure your microphone is on, please?
A. It is.
Q. And can you please state your name and business address for the record?
A. My name is first initial R. Thomas Beach. Business address, 2560 9th Street, Suite 213-A, Berkeley, California 94710.
Q. And what is that business?
A. I have an energy consulting firm Crossborder Energy.
(Direct Testimony and Exhibits of R. Thomas Beach identified)
BY MR. RITCHIE:
Q. And did you prepare direct testimony and the accompanying exhibits on behalf of Sierra Club in this proceeding?
A. Yes, I did.
Q. And do you have any corrections to that testimony here today?
A. Yes. I just have one minor correction on footnote -- on page 45 of testimony, footnote 60. That footnote refers to footnote 29 above and the

accurate reference is to footnote 43 above.

And then the one other correction is that in two places, first on page six, line 111 and again on Page ten in footnote eight, I reference California's increase in its renewable portfolio standard to 50 percent by 2030. And in those locations, I say that the legislature had passed that increase and the governor was expected to sign it.

I just wanted to update the testimony that he actually did sign it.

Q. Thank you, Mr. Beach. And with those corrections, is the testimony true and correct to the best of your knowledge?

A. Yes, it is.

Q. And if asked those same questions today, would your answers be the same?

A. Yes, they would.

MR. RITCHIE: Commissioners, with your leave, I'd like to move into the record the direct testimony and accompanying exhibits of Thomas Beach.

THE HEARING OFFICER: Does any party object to that motion? Okay. The motion's granted. Thank you.

(Direct Testimony and Exhibits of R. Thomas Beach Admitted)

BY MR. RITCHIE:

Q. And, Mr. Beach, have you prepared a summary of your testimony here today?

A. Yes, I have.

Q. Please provide that summary?

A. Thank you very much. My name is Tom Beach and I appreciate the opportunity to address the Commission on behalf of the Sierra Club today.

The Sierra Club is here today to ask the Commission to keep Utah open for business. And by that, I mean open for the business of developing new clean energy infrastructure in Utah for the benefit of Utah ratepayers and the environment in Utah.

Rocky Mountain Power has asked the Commission to reduce from 20 years to three years the maximum term of power purchase contracts with new renewable generation QFs developed in its service territory under PURPA. The Sierra Club opposes Rocky Mountain Power's application.

The utility is essentially asking the Commission to interfere with the functioning of a market that was expressly designed to counter the monopoly power of the utility. Your role as commissioners of course is to regulate the utility so that it doesn't exert that power.

I started my career 35 years ago in the early 1980s on the staff of the California Public Utilities

Commission where I worked on the initial implementation of PURPA shortly after its passage by congress.

Since then, I have observed and I provide examples in my testimony from Idaho, North Carolina and California as well as from Utah that historically renewable QFs have not been developed successfully where only short-term contracts are available.

If you look on the PacifiCorp system, their operating renewable QF contracts that obviously have been successfully developed, the average contract length is 19.7 years.

It's clear to me that the intent of the utility's request in this case is to make it impossible to finance additional renewable projects in its service territory. Capital-intensive solar and wind projects simply cannot be developed successfully with three-year contracts, and there's no history of them being able to be developed on that basis.

The Rocky Mountain Power proposal is clearly an effort to relieve the utility of its must-purchase obligation under PURPA.

The utility says that it would still be required to purchase QF power under three-year contracts, but there really is no must-purchase obligation if there's nothing to purchase because projects cannot obtain financing to be built.

This step to reduce the contract term is of questionable legality under PURPA whose purpose is to encourage the development of qualifying renewable generation that can be developed at the utility's avoided cost.

If Rocky Mountain Power does not want to comply with its PURPA obligations, then there are well-established ways under federal law, Section 210 and PURPA, for the utility to replace its traditional PURPA obligation and for the state of Utah to assume greater control of over utility procurement of renewable generation in the state.

Many other states have followed this course. And their procurement of renewable generation is now under RFPs and under the same type of process that Rocky Mountain Power now uses to procure other types of resources.

However, pursuing 210(m) of PURPA may require other changes in the energy markets in Utah that Rocky Mountain Power does not seem interested in.

So, we are left with the utilities still being under a traditional PURPA obligation, the traditional PURPA must-purchase obligation.

So, now I'd like to talk a little bit about the ratepayer indifference issue. Prices in PURPA contracts are set based on the utility's avoided cost; that is, on the cost the utilities would incur for the same amount of power if it did not purchase the QF generation.

As a result, the utility's ratepayers will be indifferent on a forecast basis to the purchase of the additional solar or wind generation.

Rocky Mountain Power claims that this is too risky. However, it's no riskier than when a utility makes a long-term commitment to a new generating plant that the ratepayers will pay for through the rate base.

When the utility makes such a proposal, whether that plant is cost effective is decided using the same types of long-term forecasts that the Commission uses to set avoided cost prices for QFs using the same type of information developed in Integrated Resource Plans.

QF pricing is not like short-term hedging of energy commodities such as natural gas, oil, or short-term market power and should not be subject to the Commission's short-term hedging programs and policies for such commodities.

Renewable QFs are new steel in the ground generation projects. And no one builds those new generation projects on the basis of three-year contracts.

The Sierra Club believes that the QF market that the Commission has established in Utah is working exactly the way you designed it. There's simply no present crisis with an oversupply of renewable QFs in Utah such that the Commission needs to shorten the contract term that will no longer encourage the development of solar and wind QFs in Utah.

The Commission's method for setting avoided cost prices provides the utility with the ability to update its forward price curb for avoided costs in order to reflect changing loads and resources, changing natural gas prices, and changes in the need for generation.

As Rocky Mountain Power adds more renewable QF generation, its avoided cost prices drop as this generation replaces progressively less expensive power.

And this could be seen in the declining indicative prices that Rocky Mountain Power has provided to solar projects in its pricing queue.

These indicative prices, when compared on an apples-to-apples basis with the lowest public power purchase agreement prices for solar in the Western U.S. show that it's likely that none of the solar QFs in Rocky Mountain Power's queue are likely to be successfully developed at the indicative prices.

And even for those projects that have that in the contract, time is running out for those projects to be developed before the end of 2016 when there's the stepdown of the federal investment tax credit.

So, in short, there's no crisis. The market is working correctly and will be self limiting.

Finally, even if there are a few more QFs developed before the ITC stepdown, this fixed-price renewable generation offers significant benefits to Rocky Mountain Power's ratepayers. And these benefits are not included in the avoided cost price that the utility will pay for the power.

And Sierra Club's not suggesting that these additional benefits be included in the price. We're not proposing to change the Commission's avoided cost pricing methodology, but the existence of these additional benefits means that if you can buy additional solar and wind generation at these prices, it's going to be a good deal for the ratepayers of Utah.

First of all, there is -- the utility does have the ability to negotiate for the RECs associated with this generation. In some instances, not all, they have procured the RECs associated with QF generation, and that's a direct and quantifiable benefit to ratepayers.

The second benefit to ratepayers is avoiding price spikes. We've seen in 2000, 2001 with the California energy crisis, we've seen natural gas price spikes in 2005 and 2007. Fixed-price generation provides protection for customers against such run-ups in prices.

By bringing on more generation in the West that has zero marginal costs, it lowers the price of -- lowers the market prices generally across the whole market. And since Rocky Mountain Power is short on power, these lower market prices are an additional benefit to customers.

And finally, there is an economic development benefit for Utah. These potential solar and wind projects represent investment of potentially hundreds of millions of dollars in clean energy infrastructure in the state of Utah over the next several years.

Even if only a fraction of them are developed, they would provide Utah with economic benefits associated with the construction of modern clean energy facilities.

If these projects are not built in Utah, they could be developed in one of the surrounding states that also are rich in renewable resources.

So, in conclusion, I ask again if Utah's open for this business or is going to hang out a closed sign similar to the unfortunate recent decision in Idaho to shorten its QF contract term.

Many states in the West are rich in renewable resources and developers have options to take their business elsewhere. And so, the Sierra Club looks forward to how the Commission answers this question.

Thank you very much for your attention.

MR. RITCHIE: Thank you, Mr. Beach. Mr. Beach is available for cross-examination.

THE HEARING OFFICER: Thank you. Ms. Dutton?

MS. DUTTON: No. Thank you.

THE HEARING OFFICER: Mr. Dodge?

MR. DODGE: No questions.

THE HEARING OFFICER: Mr. Sanger?

MR. SANGER: No questions.

THE HEARING OFFICER: Thank you. Mr. Moore?

MR. MOORE: No questions.

THE HEARING OFFICER: Mr. Jetter?

CROSS-EXAMINATION

BY MR. JETTER:

Q. I do have a few questions. Good afternoon. These are probably similar to what I asked Ms. Wright.

Do you recognize or do you agree or maybe a better question would be that a 20-year contract reduces the risk of the income stream upon which financing for these projects is based?

A. Yes.

Q. And do you agree that there is any value to the reduction of that risk in income variation over the term of that income stream?

A. A value to who?

Q. In this case, I suppose it would be, there's a value in that reduction in risk to the lenders on these projects?

A. Yes. Generally, lenders on a renewable energy project are only willing to take certain risks. And generally they're not willing to take the price risk of fluctuating market prices for a new energy facility that is going to have a useful life of 20 to 25 years.

There are a lot of risks on these projects. There are development risks. There are construction risks. There are operating risks. There's environmental risks. And developers are only willing to take a certain amount of risk. And one of the risks that it's clear from the market for these projects that they're not willing to take is the risk of price fluctuations.

Q. Thank you. And so, the 20-year contract at risk, those prices are ultimately passed through to consumers and so that risk would also then be passed on to customers of the utility; is that correct?

A. Yes. And that's no different than when the utility builds any kind of plant. It's based on -- whose economics are based on a long-term forecast of what fuel prices and market prices are going to be in their service territory. Customers take that risk all the time and the

Commission is here in part to make sure that those risks of evaluated fairly.

Q. Are you familiar with how Utah calculates its QF pricing?

A. I'm familiar in general terms.

Q. Okay. Do you know in the QF pricing calculation if there is anywhere in that formula where we include the value of this risk?

A. The value of this risk to who?

Q. To the customers or to the -- either way.

A. Well, I'm not aware that it's included either in QF pricing or in the way that you would evaluate a utility-owned resource.

Q. Okay. And so, if we're estimating our best guess of a 20-year future avoided cost rate and we want to keep consumers in a position where they are indifferent to these contracts, are they really indifferent if we are placing the price risk upon the customers when we're calculating it without any evaluation of that price risk being placed on the customers?

A. Well, I think you need to -- there certainly is -- you know, there is a price risk there. Market prices can be higher or lower than what is forecasted in the model used to set the avoided cost prices.

You have to evaluate whether that risk is worthwhile given, you know, some of the other benefits that ratepayers gain from these resources which I think are significant in terms of the fact that it's new clean energy infrastructure, that's it's going to drive down market prices generally, that it can help with future carbon compliance, and that it's economic development for the state of Utah.

If you think that those benefits are worth this risk, then I think you would say, let's keep our pricing methodology in place and if more of these resources show up, that'll be a good thing.

Q. Thank you. I would just like to address one other issue. I believe you covered it briefly in your opening statement, but you had testified in your direct testimony that it was your understanding I think at the time you had written that that in Utah the utility owned the RECs for these projects?

A. I don't think so. I think I testified that the utility had acquired some RECs associated with some contracts. We did discovery on this and they provided, you know, an amount of RECs that they had procured from QFs in Utah. So, it was my understanding that they didn't get RECs associated with all of their QF contracts but that they had negotiated the acquisition of some.

MR. JETTER: Okay. That's what I would like to clarify. I have no further questions. Thank you.

THE WITNESS: Thank you.

THE HEARING OFFICER: Thank you. I think it might be a good time for a short break before your cross-examination. Why don't we break until about 3:10. We're in recess.

(Recess taken 3:00 p.m. to 3:10 p.m.)

THE HEARING OFFICER: Okay. Thank you. Mr. Beach, you're still under oath. Ms. Hogle?

CROSS-EXAMINATION

BY MS. HOGLE:

Q. Good afternoon, Mr. Beach.

A. Good afternoon.

Q. My name is Yvonne Hogle. I don't think we have met formally. I'm in-house counsel for Rocky Mountain Power.

A. Nice to meet you.

Q. Nice to meet you.

You worked for the California Public Utilities Commission in the '80s; is that correct?

A. That's correct.

Q. And you mentioned that you started your career there working on the initial implementation of PURPA; correct?

A. Yes.
Q. And so, you dealt directly with issues like avoided costs; is that correct?
A. Yes.
Q. Okay. And so, when you first started, PURPA had just been enacted in 1978; is that correct?
A. Yes.
Q. Would you agree with me that PURPA was instrumental in opening up wholesale power markets by, one, including the must-buy obligation in its provisions?
A. Yes. I generally agree with that. It opened up the generation market to a lot of new actors other than the utilities who had not been able to participate in that market previously.
Q. Well, independent power producers just multiplied in the '80s and into the '90s and into the 2000s; is that right?
A. Yes.
Q. Okay. I'd like you to turn to page 14 of your direct testimony.
A. Okay.
Q. So, on line 270, you state that California offered 20- to 30-year PURPA contracts in the 1980s with renewable QFs provided fixed energy and capacity prices

for up to the initial 10 years of the contract and fixed capacity prices for the full contract term; right?

A. Yes.

Q. And when you say, "prices," do you mean payments?

A. No. I mean prices. You only get -- if you're a QF, you only get paid if you actually produce the power. So, the energy and capacity prices were fixed.

Q. Okay. So, when they did enter into these contracts, assuming they offered the power, they would get these payments; is that correct?

A. They would get those prices used to calculate their payments, yes.

Q. Okay. And so, are these what are known as standard-offer rates? Could these be part of what you're talking about here?

A. Yes. Those -- well, that's what the contracts -- they were called standard offer contracts.

Q. And so, is it fair to say that these energy payments were established at a time of high oil and natural gas prices and forecasts that assumed the price of these fuels would increase significantly?

Do you recall from the 1980s?

A. Yes. That is what happened. In 1986 the price of oil went down. So, for a number of years those prices were above what you would consider market prices.

Q. And am I correct that the California PUC placed no limit on these rates initially when they started offering them; is that correct?

A. Are you talking about no limits on the number of QFs that could be developed?

Q. The number and volume of contracts.

A. Yes. There were no limits at that time. I would say that when the program started, California was in a dire straight in terms of electric generating capacity. The state desperately needed electric generation. And, basically, QFs were the only alternative. It was impossible to develop coal plants in California because of air quality issues.

The utilities were having great difficulty developing nuclear plants. It was actually prohibited to burn natural gas in power plants at that time. So, literally, the state's only option to meet a critical shortage of electric generating capacity was QFs.

Q. Okay. And then, but on line 275, you note that the development of these rates ceased when the long-term contracts were suspended in the late 1980s; is that correct?

A. Yes.

Q. So, do you know the year when these SO,

standard offer rates were first offered in California?

A. I believe they were started in 1983.

Q. And do you know approximately when they were suspended?

A. Well, they were suspended over a period of time. I think in the '85 to '87 timeframe was when they were suspended. There were a number of different contracts and they were suspended at different times.

Q. And do you know why they were suspended?

A. At that time that there was a concern with the drop in oil prices in 1986 and there was a concern with an oversupply of QF capacity.

Q. So, they were widely successful?

A. They were successful, yes.

Q. Beyond regulators' expectations?

A. Yes. And I think that was a learning experience. And I will say that although those prices were above market for a number of years, those projects ended up being an incredibly economic resource for the state during the 2000-2001 California energy crisis.

And the renewable QFs that were developed in the 1980s are today the least-cost source of renewable generation for California because many of those projects are still generating, you know, 30 years after they were developed. So, they have been recontracted and those contracts are among the least cost source of renewable generation today in California.

So, yeah, those contracts were above market for a number of years but you need to look at the economics over the full life cycle of those projects. And I think over their full life cycle, they were a good deal for their ratepayers.

Q. Do you feel what the California utility's reactions were to the offering and the continuation of the standard offer rates while they were valid?

A. They complained a lot.

Q. Okay. Isn't it true that they filed comments with FERC complaining, as you put it, that these and other standard offers have forced them to purchase too much capacity at too high of prices?

A. Yes, they did complain. I think if you examine what their alternatives were, their alternatives would have been building more nuclear plants. And if you look at what they actually paid for the nuclear plants that they actually built, the QF program was a much better deal.

Q. Is it fair to say that California retail customers in the '90s and maybe into the early 2000s were paying a lot more for their electricity in part due to these above-market rate PPAs?

A. Well, again, you know, hindsight's always 20-20. And, yes, there was a period of time in the late '80s into the '90s where ratepayers in California paid above what they would have paid if -- for example, if they had not entered into those contracts and had waited for gas supplies to rebound and then they'd build gas plants. But again, you know, hindsight's always 20-20.

And then it turned out that when we went through the California energy crisis in 2000, 2001, those fixed-prices resources turned out to be a very good deal for those years for ratepayers.

So, again, you have to look at it over the entire history of those projects.

Q. But for probably 20 years, California suspended long-term QF PPA contracts, is that correct, as a result of these standard-offer contracts?

A. California did not offer -- in terms of renewable contracts, they did not offer long-term contracts to renewable QFs until they started the RPS program in 2003.

MS. HOGLE: Okay.

May I approach the witness, Your Honor?

THE HEARING OFFICER: Yes.

BY MS. HOGLE:

Q. So, this, Mr. Beach, is a background

information from Southern Cal Edison's web site on Qualifying Facilities Background.

Do you have any reason to dispute that what I just handed you is just that? If you look at the bottom of the address, the web site address, you can clearly see that it is from Southern Cal Edison's web site.

A. Yes. I see that.

Q. Can you please read for me the highlighted paragraphs?

A. "The California Public Utilities Commission decided to encourage QF development further by establishing generous 'Standard Offer' power purchase contracts that utilities were required to accept from QFs.

"The CPUC also based avoided cost on the cost of owning and operating a natural gas-fired power plant, which, at the time, was the most costly of fossil fuel plants to run."

"In 1983, the bottom fell out of international energy prices and the cost of oil and gas dropped precipitously, but the lucrative terms of the Standard Offer contracts did not change, producing a 'gold rush' of new applicants.

"In response, the CPUC began to phase out the Standard Offer program. By 1986, the CPUC had

suspended the availability of new power purchase
contracts for QF projects larger than 100 kW."

MS. HOGLE: At this time, Your Honor, I would like to move for the admission of Rocky Mountain Power Cross Exhibit-1 into the record.

THE HEARING OFFICER: If anybody party objects, please indicate.

MR. RITCHIE: Mr. Chairman, I do object based on what Ms. Hogle intends to introduce by this. Mr. Beach has read that statement. She's not asked him to adopt that statement and I think she can fairly ask questions about the statement read into the record.

But I don't think we have any foundational evidence or any support to authenticate this document or to prove up this piece, this document as evidence.

He's welcome to answer questions about it, but the document itself, I don't think it's necessary to go into evidence at this time.

THE HEARING OFFICER: Okay. Thank you.

Ms. Hogle, do you have any response to that?

MS. HOGLE: Sure. I believe I established foundation already. I asked him if he believed that I received or that I printed this off of the Southern Cal Edison web site.

And it goes directly to his testimony wherein he testifies about these very same 20, 30-year PURPA contracts in the 1980s. And he was an employee of the California Public Utilities Commission.

So, I think it presents a full picture of his testimony that is not included in his testimony of the conditions and circumstances in California with QF contracts in the 1980s.

THE HEARING OFFICER: Given that this is basically a statement of a California utility that's not a party to this, I think I'm going to grant the objection to the motion to enter it but allow questions about the statements and ask the witness whether he agrees with them. But I don't think I see an evidentiary biases for putting this into evidence.

MS. HOGLE: Okay.

THE HEARING OFFICER: Thank you.

MS. HOGLE: I have no further questions. Thank you.

THE HEARING OFFICER: Thank you.

Any redirect? Mr. Ritchie?

REDIRECT EXAMINATION

BY MR. RITCHIE:

Q. Yes. Thank you.

Mr. Beach, Mr. Jetter of the Division asked you a couple questions about ratepayers assuming the risks

of long-term contracts.
Do you remember that line of questioning?
A. Yes, I do.
Q. What about short-term contracts? If the Commission was to adopt three-year or five-year contracts that have been proposed today, would ratepayers be assuming any risks from those contracts?
A. Yes, they would. They would assume the market pricing risk under those contracts because, you know, market prices can fluctuate and they are very low today, but we certainly have seen episodes in the past and I'm sure we will see episodes in the future where market prices are going to be much higher than they are today.
So, under a short-term contract, ratepayers bear the risk of those kinds of market price fluctuations. And, you know, if you live by the market, you die by the market I guess is the way to put it.
MR. RITCHIE: I have no further questions at this time. Thank you.
THE HEARING OFFICER: Okay. Thank you.
Any desire for any recross from any party?
MS. DUTTON: Can I ask a recross question?
THE HEARING OFFICER: Sure.
RECROSS-EXAMINATION
BY MS. DUTTON:

Q. It's based on the document that Ms. Hogle asked the witness to read.
In the second paragraph, the highlighted section, could you read the first sentence again?
A. "In 1983, the bottom fell out of international energy prices and the cost of oil and gas dropped precipitously, but the lucrative terms of the Standard Offer contracts did not change, producing a 'gold rush' of new applicants."
Q. And under Utah's avoided cost method, would that ever be the case in Utah that the prices would not change?
A. Well, my understanding in Utah is that the utility is able to update its avoided cost prices as natural gas prices and forward electric market curves change.
Q. And so, would you agree that the terms of the contracts would change in Utah to adjust the avoided cost price for QF projects?
A. Yes. So, a QF that's developed this year might not get the same price as a QF developed next year or the year after that.
MS. DUTTON: Okay. Thank you.
THE HEARING OFFICER: Commissioner White, any questions for the witness?

COMMISSIONER WHITE: No questions. Thank you.
THE HEARING OFFICER: Thank you.
Commissioner Clark?

EXAMINATION

BY COMMISSIONER CLARK:

Q. A couple of questions about this subject we've been discussing here.
First, the two paragraphs that you read into the record, do you disagree in any essential way with what's represented here as a description of the historical events of this period?

A. Well, I actually do disagree with some of the dates. For example, the bottom fell out of international energy prices in 1986, not 1983. And, you know, I guess I would quibble with some of the adjectives that the utility used here.
But, you know, otherwise, you know, generally, I think that what is described here is pretty consistent with what I described in my earlier testimony.
You know, I think that we've learned a lot since then in terms of updating avoided cost prices on a regular basis so they keep track with the market. We've also learned a lot about procuring resources.
So, you know, utilities often have the ability to negotiate with QFs to some extent, and so, certainly

this experience has not been repeated in California nor in any other state.

And as I earlier testified, I think in the final analysis, what California got out of what was admittedly a flawed initial process was a set of resources that over the last 30 years has stood the test of time.

Q. Did the standard-offer contracts specify a price or a formula for deriving a price?

A. The standard-offer contracts that were applicable to renewable QFs, they had ten years of fixed prices similar to what contracts in Utah have today.

But they were up to 30-year contracts but the price was only fixed for the first ten years except for the capacity price. The capacity price was fixed for the full 30 years. The energy price was fixed for the first ten years, and then after that first ten years of the contract, the energy was priced back at the market prices.

So, in terms of the energy component of those projects, they were really only above market for the first ten years. And because oil prices didn't crash until '86, some of those projects, they were probably at market for a number of -- for the first several years of those projects.

Q. How was PURPA administered, then, during the time period following the suspension of the standard-offer contracts?

A. Well, following the suspension, there were shorter term contracts available, you know. They were one-year contracts, basically, at avoided energy and capacity prices.

Initially, they did have longer term contracts with fixed-capacity prices available but not fixed-energy prices. And then they went to just -- for a period of time in the '90s, the only thing that was available was a one-year contract at short-run prices. And then California launched into its deregulation experiment which did not work out.

COMMISSIONER CLARK: Thank you. That's all my questions.

THE HEARING OFFICER: Thank you. And I don't have any. Thank you. Anything else, Mr. Ritchie?

MR. RITCHIE: No. Thank you, commissioners.

THE HEARING OFFICER: Thank you. We'll turn to Mr. Dodge.

MR. DODGE: Thank you, Mr. Chairman. The Rocky Mountain Coalition for Renewable Energy would like to call Kevin Higgins.

THE HEARING OFFICER: Mr. Higgins, do you swear to tell the truth?

THE WITNESS: Yes, I do.

THE HEARING OFFICER: Thank you.

KEVIN HIGGINS,

having first been duly sworn, was

examined and testified as follows:

DIRECT EXAMINATION

BY MR. DODGE:

Q. Would you please explain who you are and on whose behalf you are testifying?

A. My name is Kevin Higgins. I'm here on behalf of the Rocky Mountain Coalition for Renewable Energy.

(RMCRE Exhibit 1.0 and Exhibit 1.0SR identified)

BY MR. DODGE:

Q. And did you cause in this docket to be prepared and filed direct testimony and surrebuttal testimony?

A. Yes, I did.

Q. And do you have any corrections to any of that testimony?

A. I do not.

Q. And does that testimony represent your sworn testimony here today?

A. Yes, it does.

MR. DODGE: I'd move the admission of

Coalition Exhibit 1.0 and 1.0SR.

THE HEARING OFFICER: If any party objects to that motion, please let me know. Seeing none, the motion is granted. Thank you.

(RMCRE Exhibit 1.0 and Exhibit 1.0SR Admitted)

BY MR. DODGE:

Q. Thank you. Mr. Higgins, could you provide a summary of your testimony?

A. Yes, I will. Thank you. Good afternoon commissioners. While we're waxing nostalgic a little bit about PURPA, maybe you'll indulge me and allow me to point out that my very first experience as a witness was in 1984 on behalf of the State of Utah Energy Office before this Commission when the state of Utah was attempting to implement PURPA for the very first time.

And so, I now find myself 31 years later here testifying before this Commission on essentially the same topic. And I will volunteer that if I show up 31 years from now to discuss this topic, someone should encourage me to get a hobby. But you can look for me on public witness day in 2046.

Now, in my opinion, the Company's proposal to reduce the maximum term for fixed-price contracts for QFs from 20 years to three years is not reasonable nor is it in the public interest and the proposal should be rejected by the Commission.

I believe that the Commission's current approach to contract terms is reasonable and it provides an appropriate framework for encouraging QF development while protecting customer interests.

The Company is asking the Commission to abandon its long-established policy of reasonably encouraging QF development by ensuring the availability of the long-term power purchase contracts at avoided costs. In its place, the Company seeks adoption of a new policy that is clearly designed to hinder further QF development in Utah.

In supporting it's argument, the Company relies on inept comparisons to hedging and utility planning criteria while ignoring the obvious fact that the Company is compensated for its own resources in a fundamentally different and far more favorable manner than QFs are.

Take, for example, the unfavorable comparison of long-term QF contracts to hedging practices. In my view, this is an apples-to-oranges comparison.

Hedging contracts are simply an instrument in pricing the Company's fuel supply and market purchases, whereas the Company's generation assets that are served by the fuel hedges are in fact long-term obligations for which customers are bound for decades.

So, while the Company enjoys a long-term revenue security of earning returns from its assets in rate base, the Schedule 37 or 38 contract is the sole means by which a QF is compensated for its power.

The more apt comparison is not between the Company's hedging practices and long-term QF contracts but it is between long-term QF contracts and the Company's recovery of its generation investments in the rate base. In this comparison, the obligations of customers are longer term and more open ended when it comes to paying for utility-owned plant in contrast with QF contracts because utility generation assets are subject to ongoing environmental risks that are commonly addressed through environmental upgrades which customers are routinely required to fund pursuant to general rate case decisions.

You know, in the last three general rate cases in Utah, the Company has requested and been granted approval for hundreds of millions of dollars of additional rate base for environmental upgrades.

Customers are also at risk for future accelerated depreciation of utility generation assets to the extent that plant lives are shortened in response to environmental pressures.

So, there are considerable risks today for customers under the acquisition of power from utility-owned assets.

Mr. Clements argues that PURPA contracts do not go through the same extensive IRP process to determine if they are needed. In making this argument, Mr. Clements overlooks the fact that the pricing methodology adopted in Utah by this Commission relies upon the Company's IRP least-cost plan. And QF prices are tied directly to that least-cost IRP plan. This is how ratepayer indifference is accomplished.

When Mr. Clements discusses the IRP and its relationship to QF pricing, he limits his discussion to the next planned thermal resource.

He neglects to point out that the IRP calls for the purchase of around one million megawatt hours per year in front-office transactions from 2016 to 2024.

And it is those anticipated purchases that a long-term PPA with a QF would primarily be displacing, and it is the displacement of those anticipated purchases that drives the pricing in QF contracts in Utah today.

In fact, the indicative price posted in Appendix B of the Company's Q2 filing with this Commission indicates a long-term 20-year price including capacity of $33.12 per megawatt hour. That's for 100 megawatts of displacement with an 85 percent capacity factor.

So, with prices like those, it is difficult to understand the great alarm that is being expressed with regard to customer interests in protecting ratepayers.

Finally, the proposed change by the Company is likely to quash QF development in Utah at a time when implementation of the EPA's clean power plants is creating significant uncertainty with respect to the Company's long-term resource plan.

It strikes me as unwise to be signaling to QFs, particularly in light of their various renewable, zero emitting and combined heat and power attributes that their power is of little long-term value and consequently discouraging their development at a time when new environmental regulations are placing long-term resource planning in a state of flux.

This seems particularly unwise when we understand that the development of renewable zero-emitting and combined heat and power resources, each of which has a nexus to QF generation, is encouraged by the clean power plan as a means of gaining compliance.

In countering my argument, the Company points out that it's the QF, not Rocky Mountain Power, that owns the renewable energy certificates.

But this does not refute my argument. If the state of Utah, in complying with the clean power plan adopts a rate-based plan, then the availability of additional renewable energy in the state creates a marketplace from which renewable energy can be purchased or the credits or the certificates could be purchased for compliance. So, it's a supply-and-demand situation.

Yes, the Company doesn't own the RECs or most of the RECs that the QFs provide, but renewable QFs will provide a ready supply of RECs that will be available for sale for compliance.

On the other hand, if Utah adopts a mass-based plan to comply with the clean power plan, then the simple displacement of the Company's thermal generation with renewable energy will help the Company comply.

So, that concludes my summary. Thank you.

MR. DODGE: Mr. Higgins is available for cross.

THE HEARING OFFICER: Okay. Thank you.

Ms. Dutton, anything from you?

MS. DUTTON: No. No questions.

THE HEARING OFFICER: Mr. Ritchie?

MR. RITCHIE: No questions. Thank you.

THE HEARING OFFICER: Thank you. Mr. Moore?

MR. MOORE: No questions.

THE HEARING OFFICER: Mr. Jetter?

MR. JETTER: I have no questions. Thank you.

THE HEARING OFFICER: Okay. Thank you.

Ms. Hogle?

MS. HOGLE: I have no questions.

THE HEARING OFFICER: Okay.

Commissioner White?

COMMISSIONER WHITE: I have no questions. Thanks.

THE HEARING OFFICER: Commissioner Clark?

COMMISSIONER CLARK: No questions. Thank you.

THE HEARING OFFICER: I have none. Thank you, Mr. Higgins.

THE WITNESS: Thank you.

MR. DODGE: Mr. Chairman, the Coalition would also like to call Mr. Bryan Harris.

THE HEARING OFFICER: Mr. Harris, do you swear to tell the truth?

THE WITNESS: Yes.

BRYAN HARRIS,

having first been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. DODGE:

Q. Mr. Harris, could you tell us who you are and for whom you work and on whose behalf you're testifying?

A. My name is Bryan Harris. I am a project development manager for SunEdison and I am testifying on their behalf.

Q. And on behalf of the Rocky Mountain Coalition; is that correct?

A. Yes, that's correct.

(RMCRE Exhibits 2.0R, 2.0SR, and 2.0 identified)

BY MR. DODGE:

Q. Thank you. And under your direction, Mr. Harris, what was direct testimony and rebuttal testimony and surrebuttal testimony filed on your behalf?

A. Yes.

Q. And does that testimony represent your testimony here today?

A. Yes, it does.

MR. DODGE: I'd move the admission of Coalition Exhibits 2.0R, 2.0SR, and 2.0.

THE HEARING OFFICER: Okay. If any party objects to the motion, please let me know. I'm not seeing any. So, the motion's granted.

(RMCRE Exhibits 2.0R, 2.0SR, and 2.0 Admitted)

BY MR. DODGE:

Q. Mr. Harris, do you have a summary of your testimony in this docket?

A. Yes. I have a few comments I'd like to provide to the Commission to start out. SunEdison is a large independent power producer working to develop, build, and operate renewable energy projects around the world.

We are also very active in developing and constructing renewable energy projects in Utah. We've been working on quite a few projects in Utah over the last several years.

Currently, we have 22 QF power contracts in place with Rocky Mountain Power. All of those projects are either constructed or in construction.

Those projects are all located in Beaver County and in Iron County in southern Utah. I believe nine of the projects are completed with the remaining ones in construction. Those projects are currently employing about 800 construction workers in southern Utah.

The projects are an economic boon to southern Utah. They will pay a significant amount of property taxes over the life of the project as well as about 25 full-time operations jobs. I bring that up just to point out that these projects are providing a significant impact, a positive impact to the state of Utah to the counties where they are.

In addition, I believe the projects are great, are a great asset for the ratepayers in Utah. They provide a long-term contracted amount which provides -- well, the projects are contracted and they have a steady rate for the ratepayers.

The main reason why I'm testifying today is to provide some information that if those projects were not open to having a 20-year contract, 20-year term in the contract, if it was a three-year term, those projects would not be built or would not be under construction today. And moving forward, if the Commission changes the term to three years, we will not be able to build future projects in the state of Utah. And that's really the crux of my testimony today and my opening statement.

MR. DODGE: Thank you. Mr. Harris is available for cross-examination.

THE HEARING OFFICER: Thank you.

Ms. Dutton, anything?

MS. DUTTON: No. No questions.

THE HEARING OFFICER: Thank you. Mr. Ritchie?

MR. RITCHIE: No questions.

THE HEARING OFFICER: Mr. Sanger?

MR. SANGER: No questions.

THE HEARING OFFICER: Mr. Moore?

MR. MOORE: No questions.

THE HEARING OFFICER: Mr. Jetter?

CROSS-EXAMINATION

BY MR. JETTER:

Q. Yes. Mr. Chairman, I do have a few questions. Good afternoon. I'm Justin Jetter and I represent the Utah Division of Public Utilities.

You're an expert in financing qualifying facility projects; is that correct?

A. I'm an expert in developing solar and wind projects. And a critical part of that is the financing, although I would say that Sun Edison has a very sophisticated finance team that are the true experts in project finance. I work closely with them.

Q. You know enough about it to know that, at least in your testimony, you testified that shortening the contract term would make it impossible to finance these projects; isn't that correct?

A. Shortening the term to three years or five years, yes.

Q. Okay. And that's because the variability is a risk that investors are unwilling to take; isn't that correct?

A. Yes.

Q. And that's based on two factors, is that right, that if you were in an environment where you had higher avoided cost rates, you could potentially have a shorter contract term; is that accurate?

A. By shorter, you mean how many years?

Q. Yes.

A. Yes, that's correct. That's correct. It would need to be significantly higher in order to meet a three-year or a five-year contract term. I don't know how many times higher it would need to be but several fold higher I would imagine.

Q. And so, is it accurate that the decision to finance these is based both on a rate of return of the project as well as the risk involved?

A. Could you clarify that a little bit? I don't quite understand your question.

Q. Whether or not your financing department is able to seek and secure financing for QF projects is both based on the rate of return on the project that you're offering to those investors as well as the risk that is involved?

A. I would say those are two of the factors. There are additional factors as well.

Q. Okay. Thank you. And a number of witnesses today have compared QF projects to steel in the ground resources as opposed to fuel price hedging.

Do you know what the stockmarket price will be in 2035 on August 5th?

A. No.

Q. I don't know either. But is it possible that

if the Company has, let's say, a gas resource and the cost of running that gas resource is higher than the market price on that day, the Company could essentially shut off that gas resource and buy market purchases?

A. I presume.

Q. And in the alternative, if the market is considerably lower or at all lower than the cost of running that resource and there's excess capacity, the Company could run that resource at its capacity and sell the additional into the market; is that correct?

A. I presume that that's correct as well. I would add that, you know, with a gas plant, obviously there's more uncertainty what's going to happen 20 years from now than with a solar project that has contracted terms for 20 years. I think both the ratepayer and the developer have certainty they know that price is going to much more than the gas plant.

Q. Okay. But the Company does have the opportunity in the future to choose at what rate it's going to run that gas plant and that would be based on optimizing its economics with whatever the current market prices are.

Is that correct to the best of your knowledge?

A. So, I guess, so, could you clarify that a little bit more as well? So, you're asking me, if the Company -- in 20 years if the Company will be able to run their natural gas plant or not?

Q. I'm just asking that if the Company owns the gas plant, would it not have the ability in 20 years, whatever the market conditions are, to choose to run it in an optimal economic fashion, whether that be full output, no output or somewhere in between?

A. Well, I guess I have a hard time answering that question, but I guess it's hard to predict whether it would be able to run it economically or not because who knows what the price of natural gas is going to be in 20 years.

Q. Okay. But I guess if the gas price in 20 years is too high to run economically, they could shut that plant off and not produce any 20:52:30 hadn't proves any energy?

A. I would assume that would be the case.

Q. Okay.

A. And with a renewable energy project that's contracted for 20 years, they wouldn't even need to worry about that because they know what the price is today 20 years in the future.

Q. Twenty years into the future, they are also locked into purchasing every kilowatt hour that comes out of that renewable project whether that's economic or not?

A. Right, but there is a huge benefit to the ratepayers to know what that certainty is in the future to date whether it's in the money or out of the money, correct. But they do know what that is.

Q. Okay. I'm not saying the risk is the risk that your investors are unwilling to take; is that correct?

A. I would say that the certainty that comes with that is required for our investors, whether that's debt or equity, but the same benefit is also enjoyed by the ratepayers.

Q. And so, that's -- you're saying that that's a risk that your investors are unwilling to take but that that same risk is a benefit to ratepayers; is that correct?

A. That the certainty of knowing what the price is going to be paid and received is a benefit to both parties in my opinion.

Q. And how would that differ from the certainty in price of, say, a natural gas purchase in 20 years?

Would that not also be a benefit to the natural gas producer and the Company under that same reasoning?

A. I think it would if there was a contracted price for that natural gas in 20 years, presuming that it was a low price today.

Q. Okay. Thank you.

A. And not taking into account the environmental risk and other things that go along with that.

Q. Thank you. It's really been compared today, and I'm asking you because you're more knowledgeable about the development side, it's been said that the Company and ultimately these costs generally passed to ratepayers are making similar long-term hedges when they construct a new generation facility; is that correct?

A. It would seem so to me, yes.

Q. And it's also been argued that the Company does so with limited risk because it seeks a pre-approval here and --

A. Correct.

Q. -- and it recovers those through its rate base through the period in which that plant is still being used; isn't that correct? And because of the lower risk, would you expect that a rate of return on that would be commensurately lower?

A. Which risk are you talking about?

Q. So, Company-owned generation facilities.

A. Okay.

Q. Because of their reduced risk, would it be a fair assumption that their rate of return on that, then, is lower because they are more assured of the return that they'll get on that?

A. Their rate of return is lower than what?

Q. Well, that was my next question. What rate of return is SunEdison requiring to build these projects?

What's the return on equity on it?

MR. DODGE: I'm going to object to that specific question. I'm pretty sure that's considered confidential and proprietary and not something that could be disclosed in public.

THE WITNESS: That is correct.

MR. DODGE: Nor do I think it's relevant.

MR. JETTER: I think it's directly relevant. If you're going to compare, which has been done multiple times by certain parties today, if we're going to compare Company-owned resources in the long-term hedges and risk involved with those, I think the rate of return on those is important to evaluate whether financing those projects is in fact similar to financing long-term QF projects.

MR. DODGE: And that could have been asked in discovery and appropriate protections taken. It was not done. It can be disclosed publicly. If you're going to insist upon clearing the room and trying to get an answer, we'd have to go call the general counsel and see whether he's allowed to testify.

This could have been anticipated in advance. That's very highly proprietary confidential information to any developer or any company. It's not something they disclose.

MR. JETTER: Would you be able to answer whether it's higher than ten percent?

MR. DODGE: I don't know that, but if you're going to ask, the Company's return is over 15 percent before tax. So, let's get apples and apples and not oranges. But I don't know if he can even answer that. I really do not know that.

THE WITNESS: I can't answer that.

MS. HOGLE: Your Honor, excuse me. I'm sorry.

THE HEARING OFFICER: Yes.

MS. HOGLE: I think I heard Mr. Dodge testify that the Company's return was 15 percent. I'd like that stricken from the record. That may or may not be confidential or what have you, but I think that needs to be stricken from the record.

MR. DODGE: It isn't testimony. It's just my statement. So, whether you strike it or not, it's irrelevant. Take 9.8 and gross it up by tax because it's 15 point something, but if she doesn't trust my math --

THE HEARING OFFICER: Okay. Well, I think the record should reflect that that was a statement not under oath and not by a witness. And I think that covers it.

Back to Mr. Jetter. I guess I'll ask you, are you making a motion to close the hearing and take some time to deal with answering this question?

BY MR. JETTER:

Q. I'll withdraw the question. I'm not sure the value of that would be persuasive in the outcome of this necessarily. So, I'll withdraw the question, but I would like to ask kind of a corollary question with that.

If you're getting a guaranteed fixed-price payment for every kilowatt hour you deliver over the course of 20 years, is it accurate to say that, at least within that period, that your risk involved in that project is as low as the Company's risk in one of its resources?

A. I would say no, it is not. And I am not an expert in utility finance, but my understanding is, their rate of return is guaranteed. I don't know if that's accurate or not, but I know that our rate of return is not guaranteed.

There's lots of factors that go into that. If you build a wind farm and you miscalculated how much the wind blows, you can end up with a much lower return and there's no way to inflate that return. It's going to be what it is. So, I would say our risk is not comparable with a utility, with the Company.

Q. Would you say that that probably varies with

the type of resource that you're using? So, for example, would you say that solar is significantly lower risk?

A. It could be. Solar resource is generally more consistent than a wind source. So, it could be, but if a certain developer was not sophisticated enough to understand that, then they could take a lot of risk upon themselves.

Q. Thank you. You said that currently your projects employ about 800 construction workers; is that correct?

A. That is correct.

Q. And there would be about 25 ongoing full-time employees?

A. Yes.

Q. Do you know if that's more or less than there would be had that same generation come from another source like a natural gas plant?

A. I do not know on the construction side of that. I would imagine that on the operation side it's less but I do not know. For a coal plant it would be less. I don't know about a natural gas plant.

MR. JETTER: Okay. Thank you. Those are all of my questions.

THE HEARING OFFICER: Thank you. Ms. Hogle?

CROSS-EXAMINATION

BY MS. HOGLE:
Q. Just a few questions. Were you in the room when Mr. Beach testified that current avoided cost prices are about $30 per megawatt hour?
A. I was.
Q. Would it surprise you to know that the 20-year levelized price of some of SunEdison's contracts is around $100 per megawatt hour?
A. It would not.
Q. Okay. On cross-examination you testified that it was a benefit for customers to have fixed-price contracts because they know what it costs for 20 years let's say; is that correct?
A. That is correct.
Q. How is that a benefit for ratepayers if current market prices stay for 30 years -- for the 20 years, how would that be a benefit?
A. At the time -- so, SunEdison has signed 22 power purchase agreements. And first of all, maybe I should back up a little bit. So, the power purchase contracts that you're referring to are the Schedule 37 power contracts; correct?
Q. Correct.
A. Okay. So, those contracts make up a small portion of SunEdison's portfolio of megawatts, probably

around 20 megawatts. And so, those higher priced power purchase contracts were executed under a former avoided cost methodology which took into account a significant capacity cost, capacity payment which would be counted for about half of the energy of payments and the other half was energy payments. So, the total of the project. So, probably about 20 megawatts is what you're referring to. The larger contracts, and I would say 95 percent of contracts that SunEdison has signed is significantly lower than that, less than half of that in general terms.

So, I would say that the majority of our contracts are significantly beneficial to ratepayers. The first contracts that we signed were developed under avoided cost methodology, they give a lot more benefit to capacity and because solar projects do generate during the day, they do receive a significant capacity payment.

And I think that whole argument and discussion that was discussed in one of the dockets whether that was fair or not. And I think since that was -- since the capacity payment was removed from the avoided cost methodology, I think it was determined that that did not benefit the ratepayers.

So, I would concede that on those approximately 20 megawatts, it probably wasn't a good deal for the ratepayers, but I would say that the system is working because after we sign those contracts, then that issue is brought before this Commission and they were able to remove that at their discretion.

And so, I believe that the current avoided cost methodology is very beneficial to ratepayers. Hence, the $33 that you mentioned earlier.

MS. HOGLE: I have no further questions. Thank you.

THE HEARING OFFICER: Thank you. Any redirect?

MR. DODGE: No. I have none. Thanks.

THE HEARING OFFICER: And Commissioner Clark?

EXAMINATION

BY COMMISSIONER CLARK:

Q. Good afternoon, Mr. Harris. Thanks for being here. I have some questions for you about the projects that you refer to early in your direct testimony.

Were they all constructed on the strength and financed on the strength of purchase power agreements that the Commission approved?

A. Yes -- no, they were not. So, the Schedule 38 projects were. The Schedule 37 projects did not need approval from the Commission.

Q. And as to the Schedule 38 projects, a number of those aren't yet completed if I'm correct; is that right?

A. None of the Schedule 38 projects are completed.

Q. And what's the completion date that you're contemplating, the operations date for those?

A. They will be completed between June and September of 2016.

Q. Do you have experience in seeking financing for these sorts of projects that involves a stream of payments that's different than 20 years?

A. I do not.

Q. Do you know whether your company does?

A. Yes. I believe they do.

Q. And do you have any knowledge of the Company's experience in seeking financing?

A. I have general knowledge but not details. But we do develop projects in different markets in different parts of the country and --

Q. And can you put boundaries on the financing arrangements that you're familiar with, the high side and the low side in relation to the duration of the payment streams or the pricing, the periods of time over which the pricing is fixed?

A. Yeah. So, generally, there are some parts of the country where some markets that are more liquid than Utah or the terms are less than 20 years.

However, there are hedging instruments available in those markets that are used in order to contract out the power for a longer term. And I don't understand the nuances of how that works because I haven't worked with them specifically.

But if you're in a liquid market and you can hedge that out further, then that creates the certainty that banks and investors need if that makes sense.

Q. And when you say, "less," how much less?

A. I believe 15 years in some of those markets. However, the caveat is at the end of the 15 years, the projects are still located in a liquid market where they can readily sell the power from those projects.

Q. In those arrangements or any others that you're aware of -- well, before I ask that, actually, what's the high side, in other words --

A. The longest term --

Q. Right. Right.

A. We've done 25 years and I believe there are some 30-year power purchase contracts. And obviously, from a developer, the longer the better. The cost of capital goes down with the longer terms and hence the lower price of the PPAs that we can enter into.

Q. In any of these arrangements that you're aware of, is there a provision for adjusting either the energy or the capacity payment before the expiration of the term?

A. I really don't know the answer to that. I presume that there may be, but I really don't know the answer to that.

Q. Regarding your testimony that PacifiCorp's proposal would -- I don't want to mischaracterize it, but would either halt or significantly retard the development of QF projects, do you have a sense of where the tipping point is between three years and 20 years?

A. You know, that's a good question and obviously we've thought about that. And we don't have a good answer to that. We know that we can finance a 20-year project or a 20-year contract term.

Could we contract a 19-year? I would think we probably could. But where that starts stops, I don't know. But what I do know is that the shorter term, the more difficult it becomes and the higher our cost of capital becomes and it makes projects less financially viable overall because the cost of capital increases because there's more risk introduced.

COMMISSIONER CLARK: That's all. Those were all my questions. Thank you, Mr. Harris.

THE HEARING OFFICER: Commissioner White?

COMMISSIONER WHITE: I have no questions. Thanks.

THE HEARING OFFICER: I don't have any.

Thank you. Mr. Dodge?

MR. DODGE: As a final witness, the Coalition would like to call Hans Isern.

THE HEARING OFFICER: Mr. Isern, do you swear to tell the truth?

THE WITNESS: I do.

THE HEARING OFFICER: Thank you.

HANS ISERN,

having first been duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. DODGE:

Q. Would you please state for the record who you are, for whom you work, and on whose behalf you're testifying?

A. Yes. My name is Hans Isern. It's spelled H-a-n-s. And the last name is I-s-e-r-n.

I am the senior vice president of origination for sPower. sPower is a Utah-based IPP.

Q. I apologize, Mr. Isern. I've been calling you Isern. You were too nice to correct me before.

A. That's fine. Everybody does.

(RMCRE Exhibit 3, 3.0R, and 3.0SR identified)

BY MR. DODGE:

Q. Mr. Isern, did you cause to be developed and

filed in this docket direct testimony, rebuttal testimony, and surrebuttal testimony under your name?

A. Yes.

Q. And do you adopt that testimony here as your testimony in this proceeding?

A. I do.

MR. DODGE: Mr. Chairman, I'd move the admission of Coalition Exhibits 3, 3.0R and 3.0SR?

THE HEARING OFFICER: If any party objects to the motion, please let me know. Seeing no objections, the motion's granted.

(RMCRE Exhibits 3, 3.0R, and 3.0SR Admitted)

BY MR. DODGE:

Q. Mr. Isern, would you provide a summary of your testimony?

A. Absolutely. sPower believes that the current 20-year PPA term is proper and should remain in place. Anything less we believe will be a major blow to utility scale renewable development.

We further believe that capital and jobs will leave Utah based on any decision of that sort. And pricing under three-year PPA terms very well might be higher than pricing under longer PPA terms due to the risks involved and the requirement for capital providers such as ourselves to invest in projects.

Essentially, for three-year and five-year terms, we very likely just won't do. We'll move our development efforts and dollars to another state for, you know, terms and the kind of, call it the 15- to 20-year range, it would be very difficult for us to do and would severely impact our ability to arrange for low-cost financing.

We have discussed this both with our own board and investment committees as well as our tax, equity, and debt providers. And everyone had the same reaction that we did. One of the items that I don't think has been covered well thus far is the categorization of risks. And our opinion, the benefits of a long-term QF pricing are two ways.

It does benefit developers who need long-term price certainty for power sales, but we also believe that it benefits ratepayers who likely intend to be in the Utah market purchasing energy for long periods of time who would like to not be exposed to risks of long-term purchases.

Furthermore, we think that the QF program is working very well as of today as evidenced by the PPA rates going from over $60 down to 60 to 50 to 40 to 30. That's what should happen in competitive markets, and we view that as a success, not as a reason for concern.

We also believe that 20 years is the current industry standard. It is the standard for reasons. That is the usual finance tenor of debt that gets put on the projects. And I have found it interesting that, you know, Rocky Mountain Power might consider entering into a 15-year coal supply provision because that is standard for coal. Our standard is 20 years.

So, we would ask not to have our standards significantly changed as well. I think that concludes my summary.

MR. DODGE: Thank you. Mr. Isern is available for cross-examination.

THE HEARING OFFICER: Thank you.

Ms. Dutton, anything?

MS. DUTTON: No questions.

THE HEARING OFFICER: Mr. Ritchie?

MR. RITCHIE: No questions.

THE HEARING OFFICER: Mr. Sanger?

MR. SANGER: No questions. Thank you.

THE HEARING OFFICER: Mr. Moore?

MR. MOORE: No questions.

THE HEARING OFFICER: Mr. Jetter?

CROSS-EXAMINATION

BY MR. JETTER:

Q. I do have a few questions. Good afternoon.

Thank you for being here.

Is it correct that a big part of your job in evaluating the way in which you finance a project is evaluating the risk involved with that project?

A. Absolutely.

Q. And is it also -- generally, your testimony has been that, I believe you had said that you might be able to finance a 15- to 20-year project and then you generally only finance 20-year or longer projects; is that correct?

A. That's correct. We have financed 15-year projects in states and markets where there are other incentives. For example, in North Carolina, there was a large state tax credit that provided additional revenue to offset the fact that it is a shorter term PPA.

We've seen the same in certain Northeast states such as Massachusetts which have very high prices. Essentially, what that leads to is front loading of the revenues. So, we've been comfortable in certain circumstances with shorter term PPAs, once again, in the 15-year time range when there are other significant revenue streams to help keep investors cool.

Q. Okay. And so, really, that's just based on a higher rate of return for that investment; is that correct?

A. Not necessarily. Think about the percentage of revenue that is contractually guaranteed.

Q. Okay. And the more percentage that's guaranteed, the more likely you are to lend on it; is that correct?

A. Yes. Not exactly lend but provide capital.

Q. Okay. And in that formula, do you compare -- essentially, you would make money by having a variation or a difference between the cost of the capital to your company and then the rate at which you seek return on that capital when you lend it to one of these projects?

A. Somewhat, yes. We're an equity provider. So, we would provide cash equity into the projects and then earn a return over time. Usually most of that return comes from revenues under a long-term PPA.

Q. Okay. And would you say, then, that the ability to provide financing for a project, then, is dynamic? It changes with cost of capital in the market or other resources? It's not a fixed number that's always going to be the same?

A. Well, I suppose that the ability to provide capital or the availability of capital does change from year to year. That said, in my experience and in the past multiple years of having renewable projects financed, no one has been doing three- to five-year PPAs.

And the industry standard has been 20.
We've seen a lot of 25-year PPAs as well.

Q. I'd like you to change to a slightly different line of questioning here just briefly.

You had mentioned that you think that the Utah QF pricing mechanism, our method of calculating the price has been working appropriately because as each additional resource is added to the queue, the price is lower. Eventually that would presumably I guess reach zero.

Is that ...

A. I don't know about reaching zero but having your marginal costs decrease with increasing supply is consistent with my understanding of the intent.

Q. Okay. And so, you could have a perfectly working-well market where you have a lot of QF applications and a lot of QFs being built; is that correct?

A. Yes.

Q. And you could also have a perfectly working-well market where there are no QF applications and none being built; is that correct?

A. Well, I don't think that would be a QF market, then. If there's no participants, I don't see how you would have the existence of a market.

Q. Well, isn't it your testimony that as the

prices being paid decrease that your supply would decrease?

A. Yes. So, efficiently or effectively, you have a dynamic mechanism to ensure that the most economically viable projects get built and those that are not economically viable, they would not accept the QF price and would exit the queue.

Q. Okay. And At some point, you would reach a point where there is not another economically viable project; is that correct?

A. Not necessarily because conditions will change so that you might reach that point where you don't see anything for a year or two years.

But, you know, as there are fluctuations and panel prices and other costs, as there are fluctuations in natural gas prices, you might see it become more viable to once again develop under the QF program.

Q. Thank you. And so, following up on that, it would be fair to say, then, that it's certainly possible, then, to have a multi-year period with no QFs being built and it would still qualify in your opinion as a market that's working well?

A. I don't know if I would say it's working well if you have multiple years where no QF projects are being built. It might be working well if you have low volume for a couple of years, but without any specifics of the example, it's hard for me to opine.

Q. Let's just assume everything stays equal, energy prices stay equal and each QF in the queue displaces a reduced value and so each QF subsequently receives a lower value.

In an efficient market, would you not expect that you would reach a point where there are no more efficient projects to be built and that would be the optimum number of QFs?

A. I suppose, theoretically, if PacifiCorp is -- other supply stays statistic and their load stays static, you know, and a lot of -- I think you said if all else stays equal, then, yes, they would expect for there to be a set number of QF projects developed unless, you know, developers can somehow create more economically attractive projects over time, but assuming that they can't, then, yes, there would be a point where you would fill up the abilities of QFs to provide a benefit to ratepayers and to obtain contracts.

Q. Thank you. And so, wouldn't that ultimately reach the conclusion that the number of QFs being built in a particular period is not necessarily indicative of whether the market is working correctly?

A. Well, I don't know if your example is really realistic because it assumes a lot of things that we don't see in practice.

In my opinion, a working QF market would see contracts being signed at declining marginal prices. Now, that might take time to get there. I don't think anyone would expect, you know, your QF program to develop overnight. I don't think anyone would expect it would, you know, fill up in a number of months.

But there would be period as projects are developed and development cycles can range from I guess six to 48 months depending on the size of the project.

And during that time, you would start seeing the marginal price decreasing as more and more projects are brought on line, all else being equal.

Q. And let's say hypothetically you are in an environment where you have a 30 percent tax credit and that tax credit ends.

A. Yes.

Q. And in an efficient market, would you expect that you would reach every QF or nearly every QF that could be developed economically taking into account the 30 percent tax credit. Once that tax credit ends, would you expect to see the need for QFs?

A. I think that it would take some time. I think that the ITC expiration at the end of '16 would definitely hit the pause button on QF CODs.

Q. And whether there are new QFs built in the subsequent years, would you say that that may or may not be a reflection -- may not be I guess a reflection of whether the market is working well or whether it's not working well?

A. Well, the ITC would be an external factor that would effect the economic viability of the project. So, we're not asking for, you know, higher avoided cost pricing because the ITC is expiring. We're asking for the PPA terms to remain unchanged at 20 years.

Q. And do you think -- I guess -- let's ask a slightly different question.

At the current avoided cost rates, without the tax credit, is it likely that you would finance a 20-year project based on the costs that you're seeing today for those projects as well as the avoided cost rate of, let's say, $40 a megawatt hour?

A. I think that would be difficult and we would need to see significant movement in EPC costs that would be essentially construction and then your equipment costs.

MR. JETTER: Okay. Thank you. That's all the questions that I have. Thank you.

THE HEARING OFFICER: Thank you, Mr. Jetter.

Ms. Hogle?

MS. HOGLE: I have no questions.

THE HEARING OFFICER: No questions? Okay.

Mr. Dodge, any redirect?

MR. DODGE: No. Thank you.

THE HEARING OFFICER: Okay. Thank you.

Commissioner Clark?

EXAMINATION

BY COMMISSIONER CLARK:

Q. Mr. Isern, in the descriptions that you've given us of the kinds of arrangements, PPA arrangements that are acceptable to the Company in terms of development, do any of those or have any of those involved some form of adjustment or adjustability either to the energy component or the capacity component?

A. No, none that I can think of. Everything is under a fixed-price contract. There may be escalation built into the pricing but it's still fixed from day one and then, you know, each year your contract price may vary but it is a fixed price from the day you sign through the delivery term of the PPA.

COMMISSIONER CLARK: Thank you. That's my only question.

THE HEARING OFFICER: Commissioner White?

EXAMINATION

BY COMMISSIONER WHITE:

Q. With respect to the ITC eligibility, I understand from the testimony given today that it's set to expire at the end of this year.

For eligibility purposes, does a QF have to reach the commercial operations day or is it a certain amount of construction or capital spent to be eligible for that ITC?

A. Yeah. I might have misspoken. The ITC deadline would be to have a project in service by the end of 2016. If you are not in service and delivering energy and receiving revenue, then you would not qualify for the ITC.

There is some discussion about amending that to have started construction language where developers and financiers can invest a certain amount of money and start work on a site to qualify it, but as of today, the projects must be in service and delivering energy and receiving revenue as of December 31st, 2016.

COMMISSIONER WHITE: I have no further questions.

THE HEARING OFFICER: Okay. Thank you. I don't have any. Thank you, Mr. Isern.

MR. ISERN: Thank you.

THE HEARING OFFICER: Mr. Dodge, anything further from you?

MR. DODGE: That's all. Thank you.

THE HEARING OFFICER: Okay. Does any party have anything else before we adjourn?

MR. RITCHIE: Mr. Chairman?

THE HEARING OFFICER: Mr. Ritchie, yes.

MR. RITCHIE: I did want to ask about whether a briefing schedule would be available here. I would say from Sierra Club's standpoint, I think it could be helpful in this case.

In particular, I think there was some issues addressed about the legality of some of the proposals under PURPA. And if that gets into some pretty complicated legal questions, that we would like to brief.

THE HEARING OFFICER: Okay. So, we have a request from the Sierra Club for legal briefing.

Let me ask all the parties to comment on that. Why don't we start with the applicant.

MS. HOGLE: I would leave it up to the Commission. If the Sierra Club is going to brief, the Company would then want the opportunity to do so as well.

THE HEARING OFFICER: Okay. And, Mr. Jetter?

MR. JETTER: I think from the Division's perspective, we're probably a little indifferent. We're happy to do it if the Commission thinks it's of value.

I guess that's probably my response. Thanks.

THE HEARING OFFICER: Okay. And, you know what, to save time, why don't I go back and say, do you have thoughts on timing or length?

Why don't we go back to Mr. Ritchie. And I'll still get around to everybody, but I wanted to get those two issues out of the way.

MR. RITCHIE: The immediate thing that comes to mind for me is Thanksgiving. That's why I would maybe say the week sometime after Thanksgiving.

THE HEARING OFFICER: Okay. Ms. Hogle?

MS. HOGLE: So, that would mean next week and then Thanksgiving week and then they would be due the week after Thanksgiving. Is that --

MR. RITCHIE: I would normally say two weeks but two weeks puts us right there in that Thanksgiving holiday. So, I would say, you know, go to the following week.

MS. HOGLE: And I think that would be appropriate, and I would add that it would be one round submitted by everybody at the same time.

As far as length, I'm not sure. I think there should be a limit. Again, I think I would leave it up to the Commission to determine.

THE HEARING OFFICER: We stop reading after the limit. Thank you. Mr. Jetter?

MR. JETTER: That's a reasonable schedule for us. I don't think anyone would need a lot of pages to cover it. So, whatever page limit the other parties or the Commission would like.

THE HEARING OFFICER: Okay. Thank you.

Mr. Moore?

MR. MOORE: The Office would be would be happy to go along with the Division's recommendation.

THE HEARING OFFICER: Okay. Thank you.

Ms. Dutton?

MS. DUTTON: I think that if the Commission feels it's necessary, then we would definitely comply and submit a brief.

THE HEARING OFFICER: Mr. Dodge?

MR. DODGE: Yeah. I think maybe the Commission's sort of practice is if someone feels it would be useful unless the Commission feels otherwise that that's been accommodated. And I encourage you to do that. I guess I might suggest one additional as a personal item. And that is, it would be work better for me if we went into the following week, the 11th of December or something like that. Kind of splitting the holidays.

THE HEARING OFFICER: Okay. Thank you.

Mr. Sanger?

MR. SANGER: If other parties believe that briefs are necessary, then we would support that. We're not asking for briefing, but if other parties believe it's necessary, we would support that.

As late as possible for the briefs given the holidays. So, whatever the Commission wants but the later the better for us.

THE HEARING OFFICER: Okay. Should we deliberate just for a moment or two and chat? Why don't we take a recess until about, I'm going to say 4:40.

Thank you.

(Recess taken from 4:36 p.m. to 4:40 p.m.)

THE HEARING OFFICER: Okay. We're back on the record to address the issue of legal briefing.

Any party who desires to express to us their position on legal issues with respect to interpretation of federal or state PURPA may do so by Wednesday, December 9th within a 10-page limit. And we will consider anything submitted by that date before we finalize our order. Anything further from anyone?

(Discussion off the record)

THE HEARING OFFICER: The witnesses, if you have your summary in writing, the court reporter would appreciate having a copy of that if you have it here with you. And seeing nothing further from anybody -- oh, sorry.

MR. SANGER: Your Honor, I would just like to ask the question so I understand. You said the legal issues on the interpretation of PURPA. Do I read that as the legal brief should be limited to only those legal issues or whether it would be broader than that?

THE HEARING OFFICER: Well, I think the request was for legal briefing, not for necessarily closing statements or something to that effect.

Since it wasn't a brief that the Commission asked for, it was something requested by the parties, I was, I think, just trying to be helpful in my explanation, but I don't think we're limiting it to any legal issues. I think any legal issue that any party wants to address is not off the table.

MR. SANGER: Okay. I wanted to give you whatever you want. Okay. Thank you.

THE HEARING OFFICER: And seeing nothing further, we are adjourned. Thank you.

(Proceedings concluded at or about 4:42 p.m.)

CERTIFICATE

This is to certify that the foregoing proceedings were taken before me, CLARK L. EDWARDS, a Certified Shorthand Reporter and Notary Republic in and for the State of Utah, residing at West Jordan, Utah;

That the proceedings were reported by me in stenotype and thereafter caused by me to be transcribed into typewriting, and that a full, true, and correct transcription of said proceedings so taken and transcribed is set forth in the foregoing pages, inclusive.

I further certify that I am not of kin or otherwise associated with any of the parties to said cause of action, and that I am not interested in the event thereof.

Clark L. Edwards

Clark L. Edwards, CSR
Utah License No. 109221-7801

R