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COMMISSIONERS

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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142 **NOTICE OF FILING SURREBUTTAL TESTIMONY (RATE DESIGN) AND EXHIBITS OF MICHAEL D. MCELRATH AND KEVIN C. HIGGINS ON BEHALF OF FREEPORT MINERALS CORPORATION, ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION AND NOBLE AMERICAS ENERGY SOLUTIONS LLC**

Freeport Minerals Corporation, Arizonans for Electric Choice and Competition (collectively "AECC") and Noble Americas Energy Solutions LLC (Noble), hereby submit the Surrebuttal Testimony (Rate Design) and Exhibits of Michael J. McElrath and Kevin Higgins on behalf of AECC and Noble in the above captioned Docket.

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Arizona Corporation Commission
DOCKETED
FEB 23 2016
DOCKETED BY

RESPECTFULLY SUBMITTED this 23rd day of February, 2016.

FENNEMORE CRAIG, P.C.

By: ______________________________

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Parties of record

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	)	DOCKET NO. E-04204A-15-0142

Surrebuttal Testimony of Kevin C. Higgins

on behalf of

Freeport Minerals Corporation,

Arizonans for Electric Choice & Competition and

Noble Americas Energy Solutions LLC

Rate Design

February 23, 2015

Q. PLEASE STATE YOUR NAME, AND BUSINESS ADDRESS.

A. Michael D. McElrath, 333 North Central Avenue, Phoenix Arizona.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Freeport Minerals Corporation ("Freeport") as its Director of Energy Services.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. Arizonans for Electric Choice and Competition ("AECC"), of which Freeport is a member.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND QUALIFICATIONS.

A. I have over 40 years of experience in the energy field beginning with 16 years with a natural gas utility with increasing responsibilities in 3 different states. I have worked in the mining industry for 28 years dealing with energy matters for 3 different mining companies. Today, I am responsible for the power and natural gas supplies for Freeport's mines in North America, South America and Africa.

Q. HAVE YOU TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION (THE "COMMISSION") IN OTHER DOCKETS?

A. Yes. I have testified in a number of dockets before the Commission beginning in 1994.

Q. HAVE YOU TESTIFIED BEFORE ANY OTHER PUBLIC UTILITY COMMISSION?

A. Yes, I have testified before the Public Utility Regulatory Board in El Paso, Texas, the Public Utility Commission of Colorado and the Federal Energy Regulatory Commission in various dockets over the years.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to respond to the Direct Testimony of Mr. Gary Yaquinto, Director of the Arizona Investment Council ("AIC"), concerning UNS Electric, Inc.'s ("UNSE") proposed Experimental Rider 14 ("buy-through") Tariff.

Q. WHAT IS YOUR PRIMARY CONCLUSION AFTER REVIEWING MR. YAQUINTO'S DIRECT TESTIMONY CONCERNING THE PROPOSED BUY-THROUGH TARIFF?

A. Mr. Yaquinto's opposition to the buy-through tariff is based primarily on the AIC's desire to maximize profits for the state's investor-owned utility investors it represents, despite claiming on the organization website that "Arizona investment strategies must be approached from a statewide perspective, with coordination among key leaders within the ***business***, investment and government communities...." and that "it is critical that Arizona establish a climate that will support and encourage investment."[1]

Q. WHAT SUPPORTS YOUR GENERAL CONCLUSION THAT MR. YAQUINTO'S TESTIMONY CONFLICTS WITH ONE OF AIC'S STATED MISSION GOALS OF ENCOURAGING ECONOMIC INVESTMENT IN ARIZONA?

A. Mr. Yaquinto claims that the proposed buy-through tariff represents a "free ride" for a few existing customers, and would enable a handful of "elite" corporate entities to take advantage of market opportunities, making them "a select group of privileged, large customers." Using such "loaded" terms to describe Freeport and other members of the AECC – all of which help to drive Arizona's economy and provide jobs in UNSE's service territory and throughout the state – does not lend itself to establishing a collaborative climate that will support and encourage

[1] Exhibit 1: History and Mission Statement, AIC Website

investment.

Q. DO YOU BELIEVE THAT IF THE BUY-THROUGH TARIFF IS APPROVED, ANY CUSTOMER PARTICIPATING IN THE PROGRAM WOULD BE RECEIVING A "FREE RIDE" AS MR. YAQUINTO SUGGESTS?

A. Absolutely not. Mr. Yaquinto freely admits that a major thrust of this rate proceeding is for UNSE to modernize its rate design in a way that moves customer classes closer to their actual cost of service. Industrial and commercial customers like Freeport and other members of AECC have historically paid electricity rates that more than reflect their true cost of service, and will very likely continue to subsidize other customer classes who do not pay their true cost of service after the conclusion of this proceeding.

Q. HOW DO YOU RESPOND TO MR. YAQUINTO'S ASSERTION THAT THE COMMISSION SHOULD CONSIDER THE RESULTS OF ANOTHER "EXPERIMENTAL" PROGRAM ("AG-1" TARIFF), PREVIOUSLY APPROVED FOR ARIZONA PUBLIC SERVICE COMPANY ("APS"), BEFORE APPROVING AN EXPERIMENTAL PROGRAM FOR UNSE?

A. APS' AG-1 program thus far has provided material cost savings for Freeport and other large customers without any detrimental impact to APS' other customer classes. As for his assertion that the Commission should wait and evaluate the results of the AG-1 program before approving a buy-through mechanism for UNSE, Mr. Yaquinto clearly does not recognize the benefit that approval of the buy-through tariff would have on continued economic investment in UNSE's service territory and throughout Arizona.

Q. WHY IS FREEPORT INTERESTED IN SUPPORTING A BUY-THROUGH TARIFF IN THIS PROCEEDING?

A. Even though Freeport's electric load in UNSE's service territory is minimal at this time, as a member of AECC, Freeport believes that the buy-through tariff proposal represents an important policy decision for the Commission as to whether to provide market options or choice in generation services for high-load industrial and commercial customers, not only in UNSE's service territory, but on a state-wide basis in areas served by Commission jurisdictional entities. As the AIC itself notes, investment strategies must be approached from a state-wide perspective, and that same reasoning applies to Freeport and other member of AECC.

In that regard, Freeport is a multinational corporation with operations in several continents and countries throughout the world. Given the current weak commodity price environment, Freeport has taken aggressive actions to enhance its financial position implementing significant reductions in capital spending, production curtailments at certain North and South America mines (including curtailments at the Sierrita and Miami operations in Arizona) and actions to reduce operating, exploration and administrative costs. Other AECC members face similar choices. This is the nature of having to compete in a competitive market. In considering the options, several factors come into play, and in Freeport's experience, those jurisdictions that provide market options for the purchase of electricity can be superior climates for continued investment compared to those that do not. If the Commission were to reject UNSE's buy-through tariff proposal in this proceeding, it would send a negative signal to the business community at large that the prospect of market purchases for electricity – even on a limited basis – is unlikely to materialize long-term in UNSE's service territory and throughout the state.

Q. DO YOU BELIEVE THAT THE PROPOSED BUY-THROUGH TARIFF, AS WELL AS SIMILAR MECHANISMS FOR OTHER INVESTOR-OWNED UTILITIES, COULD BENEFIT UNSE BY PROVIDING A MEANS BY

WHICH TO INCENT LARGE CUSTOMERS TO KEEP THEIR OPERATIONS IN ITS SERVICE TERRITORY?

A. Yes. There are significant advantages in having industrial and commercial customers located within UNSE' service territory that benefit the community at large, such as job creation, a higher tax base and corporate sponsorship of community and civic events. These benefits disappear if a corporation decides to curtail, shut down or completely move its operations from the local community as a result of market conditions.

Q. UNSE HAS ALSO PROPOSED AN ECONOMIC DEVELOPMENT RATE, WHICH OTHER INVESTOR-OWNED UTILITIES ARE LIKELY TO EMULATE IF APPROVED IN THIS PROCEEDING. DO YOU SUPPORT AN ECONOMIC DEVELOPMENT RATE AS PART OF UNSE'S OVERALL RATE DESIGN PROPOSAL?

A. Customer choice of generation supply would be the best form of economic development rate, inasmuch as customers could tailor the generation supply and pricing mechanism to best meet their needs. For example, a customer could choose to purchase 100% of its power from renewable sources. A customer like Freeport, which has historically not hedged its energy prices, could choose to purchase its power on an hourly, daily, monthly or annual basis as it wished. Absent customer choice, I believe that an economic development rate is yet another tool that UNSE and other investor-owned utilities can employ to attract economic development within the state. However, that should not preclude adoption of the proposed buy-through tariff as another tool or option for attracting or keeping large customers on the local system. The major difference is that the proposed economic development rate will only apply to an expansion of existing operations, or the location of new operations, within UNSE's service territory. By contrast, the proposed buy-through tariff and others like it would allow existing large and commercial customers (such as Nucor and Walmart) to calculate potential cost savings for existing operations in deciding whether to curtail, shut down or relocate their businesses elsewhere.

Further to this point, I note that in Mr. Hutchens' rebuttal testimony, he clarified that UNSE will not seek recovery of any lost non-fuel revenues associated with the economic development rate in future rate case proceedings, because "The long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs."[2] I believe that same reasoning can be applied to the buy-through tariff proposal, recognizing that whatever the mechanism, UNSE and its investors' willingness to pay the short-term costs will be outweighed by the long-term benefits of not only attracting, but ***retaining*** high load-factor customers within its service territory.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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[2] Rebuttal Testimony of David Hutchens at p. 16.

EXHIBIT 1

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ARIZONA INVESTMENT COUNCIL

Building economic foundations through energy, water and communications infrastructure. Our mission is to maximize the influence of utility investors on public policies and governmental actions and to support the infrastructure development in the State of Arizona.

NEWS & EVENTS

Utility Regulators Spar Over APS Political Spending
Thursday, 11 February 2016

Commission Calls Supreme Court Decision to Put Clean Air Plan Enfordcment on Hold a Win
Wednesday, 10 February 2016

Corporation Commission Seeks to Dismiss Text-Messages Case
Thursday, 04 February 2016

New Arizona Corporation Commissioner "Nervous" About Conflict fo Interest
Wednesday, 03 February 2016

Arizona Corporation Commission Names Doug Little New Chairman
Tuesday, 02 February 2016

AG Won't Seek the Removal of Utility Regulator Robert Burns
Monday, 01 February 2016

Utility Regulator Robert Burns Launches Investigation of APS Political Spending
Friday, 29 January 2016

The Arizona Corporation Commission Weighs in on Federal Court Declining Request for Stay of Clean Power Rule

Current Utility News

Current News

HISTORY AND MISSION

Originally formed in 1994 to maximize the influence of utility investors on public policies and governmental actions that may have an impact the well-being of investors and their utility investments, the Arizona Utility Investors Association (AUIA) was renamed the Arizona Investment Council (AIC) in April 2007 and given an expanded vision and mission. AIC's new, expanded mission extends to the support of infrastructure development in the State of Arizona. It is our belief that the well-being of investors in Arizona's utilities and businesses is closely linked with the capacity of Arizona's business leaders and policymakers to plan for the future. As Arizona faces the challenge of being the nation's fastest growing state, AIC is helping ensure we have a strong and sustainable infrastructure for this growth – today and tomorrow. We do this by working with Arizona's policymakers, regulators and business community to resolve the critical infrastructure needs in the areas of energy, water, and communications.

Why is An Organization Like Arizona Investment Council Important?

Over the next 25 years, Arizona's population is projected to double, reaching 13 million people by 2032. As a community, we need to ask questions today about what investments in backbone infrastructure, such as electricity generation and transmission, natural gas distribution and storage, water supply, and communications systems will be needed over the next 25 years to sustain our economy and lifestyle. We must also assess how we will pay for these investments and ensure that our utility companies have access to capital markets. Arizona's investment strategies must be approached from a statewide perspective, with coordination among key leaders within the business, investment and government communities and with input from citizens. Most important, it is critical that Arizona establish a climate that will support and encourage investment.

Additionally, a new generation of issues is bringing tremendous change to the utility industry. Changing technologies are redefining utility markets and services. Government policies and economic conditions are thrusting traditional monopolies into competition. Environmental concerns over climate change could lead to new laws, regulations and additional costs on utility companies and other businesses, and result in price increases to consumers. Utility regulators and policymakers face conflicting pressures from consumer, environmental and industry advocates. And governments at all levels are seeking financial resources through taxation to fund projects and programs. These issues can have a major impact on utility company finances and the return on your investments.

It's important that public officials and those who elect them understand the relationship between utility companies and the economic and environmental arenas in which they operate. This is particularly critical in our state, where rapid growth requires large investments in infrastructure. As an investor, it's important to understand the issues that affect your investments.

Currently, there are 41 state-funded utility consumer agencies operating across the country. Our government hears regularly from these agencies. But our government works best in this country when policies are made with input from all concerned parties. Regulators, legislators and other policymakers should also hear from investors – those individuals whose investments make utility services possible. With AIC, Arizona is one of approximately 10 other states providing a voice for utility investors at legislatures and regulatory agencies.

Our Objectives

AIC's activities are aimed at establishing a favorable investment climate in Arizona. We do so through active participation in public venues where investment in infrastructure and utilities is discussed and debated. AIC also gives high priority to public education in the areas of utility economics, service choices, new technologies, economic and environmental regulations and policies, infrastructure requirements and consumer and investor interests.

Arizona Investment Council focuses on these activities:

- Intervention and participation in regulatory and administrative proceedings
- Participating and speaking at community programs and public forums on issues of investment, infrastructure and the utility industry
- Educating regulators, legislators and other policymakers on issues on investment and infrastructure

AIC Briefs

AIC Letter Supporting CenturyLink
Tuesday, 02 February 2016

AIC'S Oppostiion to AURA's Motion to Extend Procedural Schedule
Thursday, 28 January 2016

AIC Amicus Brief to AZ Supreme Court re: RUCO v ACC
Tuesday, 15 December 2015

AIC Testimony in UNS Electric Rate Case
Wednesday, 9 December 2015

AIC Legal Memo Response to TASC
Friday, 02 October 2015

Deregulation Responsive Comments
Thursday, 17 October 2013

Deregulation Comments
Wednesday, 9 October 2013

Conferences

Click the links below to watch the upcoming debate or watch the archived debated.

July 16, 2014
Debate Webcast

Reports and Newsletters

Connect **- December 23, 2015**

Connect **- October 8, 2015**

Connect **- July 23, 2015**

Connect **- March 11, 2015**

Connect **- December 23, 2014**

Connect **- November 7, 2014**

2015 Annual Report

2014 Annual Report

Study of Studies: Economic Impacts of GHG Regulation

Carbon Controls Fact Sheet

Economic Impact of Carbon Controls In Arizona (full report)

Infrastructure Needs and Funding Alternatives For Arizona: 2008-2032 (Full Report)

Infrastructure Needs and Funding Alternatives For Arizona: 2008-2032 (Executive Summary)

Streamlining Administrative & Ratemaking Processes of the ACC

Organizing and sponsoring public forums and seminars on topics relating to investment, infrastructure and the utility industry

Providing news media with the investor's point of view

Issuing newsletters, legislative alerts and bulletins

Coordinating grassroots activities for investors throughout Arizona

Conducting research and issuing position papers in the areas of investment, regulatory process and policies and infrastructure

Participating in shareholder meetings of investor companies

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	)	DOCKET NO. E-04204A-15-0142

Surrebuttal Testimony of Kevin C. Higgins

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Rate Design

February 23, 2015

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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SURREBUTTAL TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who previously filed direct testimony in this case on behalf of Freeport Minerals Corporation, Arizonans for Electric Choice and Competition ("AECC") [1] and Noble Americas Energy Solutions LLC ("Noble Solutions")?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to certain arguments advanced by UNSE Energy ("UNSE") witness Craig A. Jones in his rebuttal testimony, and Staff witness Howard Solganick in his direct testimony, regarding revenue allocation and the proposed Experimental Rider 14 buy-through program. I also briefly discuss the rebuttal testimony of UNSE witness David G. Hutchens regarding the proposed Economic Development Rider ("EDR").

[1] Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

AECC witness Michael D. McElrath responds in his surrebuttal testimony to the direct testimony of Arizona Investment Council witness Gary Yaquinto on the subject of the buy-through program. I concur with Mr. McElrath's response to Mr. Yaquinto.

Q. What are the primary conclusions and recommendations in your surrebuttal testimony?

A. With respect to revenue allocation, or rate spread, I continue to support the revenue allocation proposed by UNSE in its **direct** testimony, and I continue to recommend that any reduction to UNSE's proposed revenue requirement be apportioned 50% to the subsidy-paying classes and 50% to the subsidy receiving classes. I also recommend that the first $908 thousand of revenue requirement reduction apportioned to the subsidy-paying classes should be used to support the Experimental Rider 14 buy-through program.

I also continue to recommend adoption of a buy-through program that is as similar as reasonably possible to the AG-1 program approved for Arizona Public Service Company ("APS"). In my surrebuttal testimony I respond to the criticisms of my recommendations by UNSE in the Company's rebuttal filing.

Finally, I note that my criticisms of UNSE's unbundled rate design for the Medium General Service ("MGS"), Large General Service ("LGS") and Large Power Service ("LPS") rate schedules has not been refuted by UNSE. I recommend that the Commission adopt the unbundled rate design I proposed in my direct testimony for these rate schedules, with minor modifications to account for the reduced revenue requirement accepted by UNSE in its rebuttal filing.

RATE SPREAD

Q. In your direct testimony you supported the revenue allocation, or rate spread, proposed by UNSE in its direct filing. Has UNSE modified its recommended revenue allocation in response to the testimony of other parties?

A. Yes. As discussed in the rebuttal testimony of UNSE witness Mr. Jones, UNSE has modified the Company's proposed revenue allocation to shift more cost recovery to larger customers and less to residential and small general service customers. UNSE has also updated its proposed revenue allocation for a revised, lower revenue requirement in response to adjustments proposed by Staff. UNSE's new proposed rate spread is designed to recover a non-fuel revenue requirement increase of $18.5 million[2] rather than the $22.6 million that UNSE proposed in its direct filing. UNSE's rebuttal revenue allocation proposal is summarized in table KCH-SR-1 below.

Table KCH-SR-1
Summary of UNSE Proposed Rebuttal Revenue Spread by Customer Class

Customer Class	UNSE Rebuttal Current Adjusted Test Year Base Revenue	UNSE Proposed Base Dollar Change	UNSE Proposed Base Percent Change	UNSE Net Dollar Change (Year 2)	UNSE Net Percent Change (Year 2)
(a)	(b)	(c)	(d)	(e)	(f)
Residential	$78,169,265	$15,928,289	20.4%	$6,606,441	8.5%
Small General Service	$12,461,200	$1,816,538	14.6%	$909,374	7.3%
Medium/Large General Service	$56,334,006	$1,236,675	2.2%	$2,257,929	4.0%
Large Power Service	$7,446,668	($669,871)	-9.0%	$189,131	2.5%
Lighting	$547,038	$75,592	13.8%	$79,050	14.5%
Total	$154,958,178	$18,387,223	11.9%	$10,041,924	6.5%

[2] This $18.5 million consists of $18.4 million in base revenues plus $0.1 million in other revenues.

Q. Please explain the difference between the UNSE proposed "base" change and the "net" change in Table KCH-SR-1.

A. The proposed base change is limited to the proposed change in non-fuel rates. The net change takes into account the projected reduction in fuel costs and also takes into account the absorption of the Transmission Cost Adjustor ("TCA") charge into base rates.

Q. Why are the net changes expressed as "Year 2" changes in Table KCH-SR-1?

A. UNSE is proposing a temporary Year 1 credit to the purchased power and fuel adjustment clause to pass through deferred savings associated with the acquisition of the Gila River power plant, a proposal that I support as reasonable. But to understand the underlying revenue allocation absent the temporary effect of the credit, it is necessary to examine the Year 2 effects.

Q. Why does your presentation of the net revenue change differ from what UNSE shows in UNSE Exhibit CAJ-4-R, Schedule H-1?

A. In the depiction of the net revenue change resulting from UNSE's proposed revenue allocation shown in UNSE Schedule H-1, the *kilowatt-hours* associated with Test Year Present Net Revenue, Adjusted Test Year Revenue, and Proposed Net Revenue are each different. The difference in kilowatt-hours is attributable to a number of causes, including load growth for some classes, loss of load for other classes, and UNSE-proposed class restructuring. These differences in kilowatt-hours among these categories make it very problematic to interpret the net revenue changes for each class as depicted in UNSE Schedule H-1. For example, the Schedule H-1 entry for LPS shows a $14.8 million reduction revenues in the column entitled "Net Change." This reduction includes the revenue effects of load that has disappeared due to large customer shut-downs as well as load that is migrated to other rate schedules. Schedule H-1 is simply not a useful representation of the true rate impacts on customer classes and cannot be used to assess the reasonableness of UNSE's revenue allocation proposal.

In contrast, Table KCH-SR-1 holds each class's kilowatt-hours constant when determining the net revenue change relative to adjusted base revenues. This approach provides a more meaningful depiction of the true rate impact on the customers in each class than does UNSE Schedule H-1. Table KCH-SR-1 also includes the full effect of absorbing pro forma TCA revenues into base rates, whereas Schedule H-1 only shows the absorption of the much lower TCA revenues that were in effect during calendar year 2014.

Q. Do the kilowatt-hour differences in UNSE Schedule H-1 affect classes other than LPS?

A. Yes. For the Residential class, UNSE Schedule H-1 includes the effects of Residential load *growth*. Thus, the "Net Change" of $10.2 million in revenues for the Residential class in Schedule H-1 includes the effect of 1.1% load growth. Interestingly, UNSE projects a net reduction in base fuel costs for Residential customers in total of $5.2 million, *including* the increased fuel usage for growth. This means that the effective fuel cost *reduction* impact on Residential *rates* is even *greater*, after accounting for the effects of load growth. My presentation in Table KCH-SR-1 accurately captures this effect.

Q. Turning back to UNSE's proposed revenue allocation, do you agree with UNSE's revised proposal to shift more cost recovery to larger customers?

A. No. As I discussed in my direct testimony, I believe that UNSE's initial proposal strikes the proper balance in allocating revenue responsibility among customer classes.

Q. What explanation does UNSE offer for its revised revenue allocation?

A. According to Mr. Jones, UNSE's modification is "along the lines suggested by Staff,"[3] although UNSE does not shift as many costs to MGS, LGS, and LPS as Staff advocates.

Q. Do you agree with the revenue allocation recommendations offered by Staff?

A. No. Staff's revenue allocations are presented by Mr. Solganick, who advocates for a long-term movement toward cost-based rates, but in smaller steps than proposed by UNSE in the Company's direct filing. Mr. Solganick proposes that the Commission should use UNSE's class cost of service study as a general guideline, but should rely on gradualism to determine the final revenue allocation in this case.[4] Staff's proposed revenue allocation is presented in Table KCH-SR-2, below. Staff presented its proposed allocation in terms of the base percentage change, Column (d), below.

[3] Rebuttal testimony of Craig A. Jones, p. 8.
[4] Direct testimony of Howard Solganick, p. 21.

Table KCH-SR-2
Summary of Staff Proposed Revenue Spread by Customer Class

Customer Class	UNSE Direct Current Adjusted Test Year Base Revenue	Staff Proposed Base Dollar Change	Staff Proposed Base Percent Change
(a)	(b)	(c)	(d)
Residential	$73,653,026	$10,563,000	14.34%
Small General Service	$11,905,151	$1,328,500	11.16%
Medium/Large General Service	$53,699,953	$5,435,055	10.12%
Large Power Service	$7,375,505	$746,486	10.12%
Lighting	$543,010	$54,959	10.12%
Total	$147,176,645	$18,128,000	12.32%

Q. Do you disagree with applying the principle of gradualism in this case?

A. No. I do not disagree with applying the principle of gradualism, so long as it is part of a genuine strategy of moving rates meaningfully in the direction of cost causation, and is not merely a device for institutionalizing permanent cross-subsidies from other customers. UNSE's original proposal – which I support – adheres to the principle of gradualism as it provides approximately $9 million in cross subsidies from MGS, LGS, and LPS customers to Residential and Small General Service ("SGS") customers while still moving in the direction of cost-based rates.[5] Staff's proposal dampens the movement to cost-based rates by increasing this cross subsidy to nearly $11.9 million. The subsidies incorporated into Staff's proposal are shown in Table KCH-3-SR, below.[6]

[5] Direct Testimony of Kevin C. Higgins, pp. 9-10.
[6] The subsidies in Table KCH-3-SR are derived from Staff Exhibit HS-4.

Table KCH-3-SR
Subsidies Included in Staff's Proposed Revenue Spread by Customer Class

Customer Class	UNSE Rebuttal Current Adjusted Test Year Base Revenue	Revenue Change Required to Achieve COS	Staff Proposed Base Dollar Change	Staff Proposed Subsidy (Paid)/ Subsidy Received
(a)	(b)	(c)	(d)	(e)
Residential	$78,169,265	$21,126,000	$10,563,000	$10,563,000
Small General Service	$12,461,200	$2,657,000	$1,328,500	$1,328,500
Medium/Large General Service	$56,334,006	($4,752,900)	$5,435,055	($10,187,955)
Large Power Service	$7,446,668	($957,900)	$746,486	($1,704,386)
Lighting	$547,038	$55,800	$54,959	$841
Total	$154,958,178	$18,128,000	$18,128,000	$0

Q. What is the basis for Staff's revenue allocation proposal?

A. In articulating the principles that he has used in allocating class revenue responsibility, Mr. Solganick states that "There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue."[7] However, Mr. Solganick actually does <u>not</u> structure his revenue allocation proposal using this mitigation mechanism. If he had, Staff's recommended (non-fuel) increase for Residential customers would be 18.48% (12.32% x 1.5), not 14.34% (as Staff is actually proposing), and the subsidy paid to Residential customers would be around $3 million less than Staff is proposing.[8]

[7] Direct testimony of Howard Solganick, p. 22.
[8] $73,653,026 x .1848 = $13,611,079, which is $3,048,079 more than the base revenue increase for the Residential class that Staff is proposing.

Instead, Staff's proposal is to increase the Residential and SGS rates by half of the increase that would be required to move these classes to full cost of service (or parity).[9]

Q. Why do you object to this approach?

A. Simply setting the increase to selected classes to half of what is required to attain parity – without linking that concept to other measurements such as the system average increase or the relationship to the increase levied on the subsidy-paying classes – is arbitrary. Staff's approach provides no assurance that UNSE rates would even be taking a *small* step in the *direction* of parity consistent with Staff's stated long-term objectives.

The unreasonable outcome that obtains from such an approach is evident when examining the results for the SGS class under Staff's proposal. According to Mr. Solganick's Exhibit HS-4, the system average non-fuel increase under Staff's proposed revenue requirement is 12.32%. To attain parity (or full cost-of-service) SGS would require an increase of 22.32% – which is 10 percentage points *above* the system average. Under Staff's proposal to increase SGS by only half of what is needed to attain parity, SGS winds up with a non-fuel increase of 11.16% – which is *below* the system average. By itself, this is a red flag, because if 12.32% is an acceptable increase for customers as a whole, it is difficult to understand why a class that is receiving a subsidy should be getting a better-than-average deal. Further, in order to fund the subsidies to the Residential and SGS classes, the MGS/LGS grouping, which warrants a non-fuel rate *reduction* of

[9] Direct Testimony of Howard Solganick, p. 24.

8.85% to attain parity,[10] winds up with a non-fuel increase of 10.12% – an increase that is just below the increase proposed for SGS. Staff's revenue allocation formulation is demonstrably unreasonable in part because it results in a subsidy-receiving class (SGS) receiving a below-average increase – and one that is very similar to the increase proposed for the class that is funding its subsidy (MGS/LGS). When this occurs, classes are not moving toward parity in a meaningful way.

Q. Do you have any other observations regarding Staff's revenue allocation proposal?

A. Yes. The framework presented by Staff in support of its revenue allocation proposal appears in Staff Exhibit HS-4. This presentation focuses exclusively on the relative class increases in non-fuel rates, without taking into consideration that a big driver behind the non-fuel rate increase is UNSE's investment in the Gila River generating plant and that the investment in that plant is expected to bring base fuel costs down. By focusing on the relative rate changes in non-fuel costs in isolation, and without factoring in the associated reduction in base fuel costs to customers, and the absorption of the TCA into base rates, Staff's depiction of the class rate impacts tells only part of the story.

To gain insight into these effects, I have updated the net rate impacts from Staff's proposed revenue allocation using updated test year base revenue and fuel costs, which are now reflected in UNSE's rebuttal filing. This update is shown in Table KCH-SR-4, below. This update changes the percentages in Column (d), but not the dollar amounts proposed by Staff in Column (c). I have also added

[10] See Staff Exhibit HS-4, line 37, Column (E).

Columns (e) and (f) to show the net change in rates implicit in Staff's proposal, using the adjusted test year base revenue presented by UNSE and the Company's projected change in fuel costs in its rebuttal filing, adjusted to keep kilowatt-hour sales for each class constant and to take into account the absorption of the TCA revenues into base rates, as I described above.

Table KCH-SR-4
Summary of Staff Proposed Revenue Spread by Customer Class

Customer Class	UNSE Rebuttal Current Adjusted Test Year Base Revenue	Staff Proposed Base Dollar Change	Staff Proposed Base Percent Change	Staff Net Dollar Change (Year 2)	Staff Net Percent Change (Year 2)
(a)	(b)	(c)	(d)	(e)	(f)
Residential	$78,169,265	$10,563,000	13.51%	$1,241,152	1.6%
Small General Service	$12,461,200	$1,328,500	10.66%	$421,336	3.4%
Medium/Large General Service	$56,334,006	$5,435,055	9.65%	$6,456,308	11.5%
Large Power Service	$7,446,668	$746,486	10.02%	$1,605,487	21.6%
Lighting	$547,038	$54,959	10.05%	$58,417	10.7%
Total	$154,958,178	$18,128,000	11.70%	$9,782,701	6.3%

The proposed net changes to each class's revenue requirement under Staff's proposal are presented in the final two columns of Table KCH-SR-4, above. This shows that the net rate impacts on the subsidy-receiving classes are dramatically lower than the impacts of the non-fuel increases that Staff focused on in isolation. Moreover, the net increases for both of the subsidized classes under Staff's proposal are significantly lower than the net increases for the subsidy-paying classes. This is a strong further indication that Staff's proposed revenue allocation and increased cross-subsidization is unreasonable.

Q. In your direct testimony you supported the revenue allocation proposed by UNSE in its direct testimony and further recommended that if a reduction to UNSE's proposed revenue requirement is approved by the Commission that it be apportioned 50% to the subsidy-paying classes and 50% to the subsidy-receiving classes. Is this still your recommendation?

A. Yes. I also recommended that the first $908 thousand of revenue requirement reduction apportioned to the subsidy-paying classes should be used to support the Experimental Rider 14 buy-through program.

Q. Given UNSE's stipulated agreement to reduce its proposed non-fuel revenue requirement increase from $22.6 million to $18.5 million, what revenue allocation results from your recommended approach?

A. My recommended revenue allocation at UNSE's lower non-fuel revenue requirement is presented in Exhibit KCH-SR-1 and summarized in Table KCH-5-SR, below.

Table KCH-5-SR

Summary of AECC/Noble Solutions Proposed Surrebuttal Revenue Spread by Customer Class

Customer Class	UNSE Rebuttal Current Adjusted Test Year Base Revenue	AECC/ Noble Solutions Proposed Base Dollar Change	AECC/ Noble Solutions Proposed Base Percent Change	AECC/ Noble Solutions Net Dollar Change (Year 2)	AECC/ Noble Solutions Net Percent Change (Year 2)
(a)	(b)	(c)	(d)	(e)	(f)
Residential	$78,169,265	$18,819,863	24.1%	$9,498,015	12.2%
Small General Service	$12,461,200	$2,345,477	18.8%	$1,438,312	11.5%
Medium/Large General Service	$56,334,006	($1,020,943)	-1.8%	$310	0.0%
Large Power Service	$7,446,668	($898,475)	-12.1%	($39,473)	-0.5%
Lighting	$547,038	$49,303	9.0%	$52,761	9.6%
Sub-Total	$154,958,178	$19,295,224	12.5%	$10,949,925	7.1%
Experimental Rider 14 Reserve		($908,000)		($908,000)	
Total	$154,958,178	$18,387,224	11.9%	$10,041,925	6.5%

My recommended approach allows all customer classes to benefit from the stipulated $4.2 million reduction in non-fuel revenues. My approach also adheres to the principle of gradualism, as substantial subsidies to the Residential and SGS classes are built into the starting revenue allocation from which the rate reductions are applied.[11] Finally, it provides for complete recovery of UNSE's revenue deficiency that is attributed to the reduction in fixed generation revenues from potential buy-through customers. Under my proposal, UNSE is able to recover its approved revenue requirement and the customer classes not eligible to participate in the program are held harmless from adoption of the buy-through provision. Moreover, non-participating customers in the buy-through-eligible classes are also held harmless – and indeed are in an improved position – relative to UNSE's initial filing.

BUY-THROUGH TARIFF

Q. Does Staff address the buy-through tariff in its direct testimony?

A. Yes. Mr. Solganick comments on the buy-through tariff. He states:

> Because the Company is not supporting this concept, there is no record describing the benefits to non-participating customers. Staff looks forward to testimony in support of the "Buy-Through". Staff does not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to all other customers. Staff opposes recouping any allegedly lost Buy-Through revenue in the LFCR and likewise opposes any deferral of allegedly lost Buy-Through revenue.[12]

[11] As explained on pp. 9-10 of my direct testimony, the interclass subsidies in the revenue allocation proposed in UNSE's direct filing, which is the starting point for my surrebuttal revenue allocation, amount to approximately $9.1 million, the large majority of which benefits the Residential class.
[12] Direct Testimony of Howard Solganick, p. 48.

Q. Do you believe your recommended modifications to UNSE's buy-through program parameters meet the requirements identified by Mr. Solganick to warrant Staff non-opposition to the buy-through program?

A. Yes, I do. My modifications to UNSE's program parameters remove any funding through the Lost Fixed Cost Recovery Mechanism ("LFCR") and ensure that the customer classes not eligible to participate in the program would be held harmless from adoption of the buy-through provision. In addition, my proposed revenue allocation relating to the $4.2 million reduction in base rates accepted by UNSE ensures that non-participating customers in the buy-through-eligible classes are also held harmless – and indeed are in an improved position – relative to UNSE's initial filing. Finally, my proposal does not require any cost deferrals, another condition identified by Staff to warrant non-opposition.

Q. Has UNSE responded to your direct testimony regarding the buy-through program?

A. Yes. UNSE witness Craig Jones generally disagrees with my recommendations. Specifically, Mr. Jones responds to the following elements of my testimony:[13]

- Mr. Jones disagrees with my proposal to reduce the minimum load size for participation and to allow load aggregation;
- Mr. Jones disagrees with my proposal to reduce UNSE's proposed management fee;
- Mr. Jones disagrees with my recommended reductions to UNSE's proposed assignment of fixed generation costs to buy-through customers;

[13] See Rebuttal Testimony of Craig A. Jones, pp. 45-51.

- Mr. Jones disagrees with my proposal for funding the UNSE revenue deficiency that is attributed to the reduction in fixed generation revenues from buy-through customers;
- Mr. Jones disagrees with my recommendation to reduce the mark-up proposed by UNSE for customers that seek to return to the standard rate schedule; and
- Mr. Jones disagrees with my proposal to clarify that the buy-through program will continue at least until the start of the first rate-effective period of a general rate case following the proposed four-year term.

I will respond to each of these items in turn.

Q. On what grounds does UNSE oppose your proposal to reduce the minimum load size for participation and to allow load aggregation?

A. In advancing my proposal to allow aggregation and to allow premises with billing demands of 200 kW or greater to participate (if they can aggregate up to 1000 kW), I pointed out that the APS AG-1 program permits aggregation and allows smaller premises to participate than UNSE proposes. Mr. Jones responds that APS is a much larger utility than UNSE and has greater economies of scale. He also argues that APS Schedule 32-L (which qualifies for AG-1) "in no way corresponds" to UNSE's MGS rate schedule. Mr. Jones also states that UNSE's obligation to propose a buy-through program is limited to the LPS class.[14]

Q. What is your response to Mr. Jones on these points?

A. I do not disagree with Mr. Jones that APS is a much larger utility than UNSE. I recognized the difference in scale between the two utilities in my direct testimony when I accepted UNSE's proposal for a 10 MW cap on buy-through

[14] Id., p. 47.

participation, which is only 5% of the 200 MW participation allowed under the APS program.

Yet, within this smaller program scope, it is reasonable and in the public interest for the opportunities to participate in the buy-through program to be broader than just the LPS class. According to UNSE's filing, this class would have only <u>four</u> customers in it. Eligibility for the buy-through program should not be limited to such a small number of customers. Experience with the AG-1 program demonstrates that there is keen interest on the part of commercial and public sector customers in participating in the market for electric power. This opportunity should be available to similar UNSE customers as well.

Regarding the comparability of the APS 32-L rate schedule to the UNSE MGS rate schedule, I note that my proposal requires a minimum size of 200 kW, which is reasonably comparable to the 400 kW minimum size for 32-L. I believe a smaller minimum size for the UNSE buy-through program is appropriate given the smaller scale of the UNSE system.

Finally, I recognize that UNSE is not *obligated* under the Fortis settlement agreement to propose a program with eligibility that is broader than the LPS class. The proposal to broaden the eligibility in this proceeding is that of AECC and Noble Solutions. The question before the Commission at this time is what type of buy-through program might be appropriate for UNSE and its customers, when considered on the merits. I believe that the expanded buy-through program discussed in my direct and this surrebuttal testimony is in the public interest and merits Commission approval.

Q. On what grounds does Mr. Jones disagree with your proposal to reduce UNSE's proposed management fee from $0.004/kWh to $0.0006/kWh?

A. In my direct testimony I pointed out that UNSE's proposed management charge was more than six times the size of the comparable charge for the AG-1 program. Mr. Jones responds by citing to APS's larger scale and also asserts that APS has indicated that the "net impact of the AG-1 program has been losses in the range of $10 million annually." Mr. Jones suggests that an inadequate management fee is partly responsible for the alleged losses.[15]

Q. What is your response to Mr. Jones on these points?

A. I acknowledge that APS has larger scale than UNSE. However, UNSE provides no analysis supporting its much larger charge. Indeed, UNSE has made it clear that the Company opposes the buy-through program. Proposing a burdensome administrative charge is consistent with such opposition. Further, there is no independent evidentiary support for Mr. Jones's assertion that the AG-1 program has incurred net losses in the range of $10 million annually for APS.

Absent evidence from UNSE that a $0.004/kWh administrative charge is cost-justified, the more reasonable approach is to set this charge in a range similar to the AG-1 program.

Q. How does Mr. Jones respond to your recommended reductions to UNSE's proposed assignment of fixed generation costs to buy-through customers?

A. Mr. Jones disputes that the assignment of 100% of fixed generation costs to buy-through customers is comparable to a stranded cost charge, as I maintain.

[15] Id., p. 48.

However, he does not offer an argument as to why the charge should be greater than the 15% planning reserve margin that I propose.

Q. Do you continue to recommend that, absent an opportunity to transition permanently to market pricing, the going-forward charges for generation-related services to buy-through customers should be limited to a charge for reserve capacity applied to 15% of the customer's billed demand priced at the unbundled generation demand charge?

A. Yes. This is a reasonable fixed generation cost charge for a customer that would not be using UNSE's generation service as part of a pilot program, such as a buy-through customer.

Q. How does Mr. Jones respond to your proposal for funding any UNSE revenue deficiency that is attributed to the reduction in fixed generation revenues from buy-through customers?

A. In my direct testimony I proposed that the first $908 thousand of any revenue requirement reduction apportioned to the subsidy-paying classes – which under my proposal are also the classes eligible for the buy-through program (MGS, LGS, and LPS) – be used to absorb UNSE's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers. In this way, both UNSE and the customer classes not eligible to participate in the program would be held harmless from adoption of the buy-through provision. In my surrebuttal testimony, I have applied my proposal to the $4.2 million base revenue requirement reduction accepted by UNSE in its rebuttal filing, as presented above in Table KCH-5-SR.

In his rebuttal testimony, Mr. Jones acknowledges that my proposal is "innovative on the surface," then simply reiterates that UNSE is opposed to the buy-through concept in any form.[16]

Q. Do you continue to recommend that the first $908 thousand of any revenue requirement reduction apportioned to the subsidy-paying classes be used to absorb UNSE's revenue deficiency ascribed to the loss of fixed generation revenues from buy-through customers?

A. Yes. My proposal limits the funding of this revenue requirement to the classes eligible for the program. My approach avoids both the burdensome fixed generation charges proposed by UNSE for buy-through customers as well as recovery of deemed lost revenues from other customers through the LFCR as proposed by UNSE.

Further on this point, I note that UNSE witness David G. Hutchens indicates in his rebuttal testimony that any lost non-fuel revenues resulting from discounts provided through the proposed EDR would be absorbed by the Company.[17] This position contrasts sharply with UNSE's position regarding the buy-through tariff, which is also an economic development tool. In the case of the EDR, UNSE is willing to absorb lost non-fuel revenues from discounts related to the sale of full requirements service, but in the case of the buy-through tariff, UNSE proposes to load fixed generation costs onto customers who would not even be buying generation service from the Company.

[16] Id., p. 49.
[17] Rebuttal Testimony of David G. Hutchens, pp. 15-16.

I believe my proposal strikes a reasonable balance, as it does not even require UNSE to absorb margins as the Company indicates it would do for an EDR contract, nor does my proposal impact customer classes that are not eligible to participate in the buy-through program.

Q. **On what grounds does Mr. Jones oppose your recommendation to reduce the mark-up proposed by UNSE for customers that seek to return to the standard rate schedule?**

A. If, prior to the end of the planned four-year term of the program, and absent Commission termination of the program, a buy-through customer seeks to return to standard generation service and does not provide one-year's notice, UNSE proposes to charge the returning customer the Dow Jones Electricity Palo Verde Daily Index price for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the customer back into the Company's generation planning. In my direct testimony, I agreed that this general approach is reasonable, but argued that the proposed $20 per MWh mark-up is excessive. I pointed out that APS's AG-1 program also requires that an "early" returning buy-through customer pay market rates for up to one year, but without an additional mark-up. I recommended that the $20 per MWh mark-up proposed by UNSE should be eliminated or significantly reduced to no greater than $4 per MWh.

In rebuttal, Mr. Jones argues that the AG-1 tariff provides for a $10 per MWh mark-up over the Dow Jones Palo Verde Index for a returning customer. He also argues that this return charge is intended to be a "penalty" and states that

"UNS Electric wants to protect itself and its customers from the types of losses that APS has experienced as a result of the AG-1 program."[18]

Q. What is your response to Mr. Jones on these points?

A. Mr. Jones misinterprets the AG-1 tariff, which I have attached as Exhibit KCH-SR-2. As is clear in the Section entitled "Return to Company's Standard Generation Service," on page 3 of the AG-1 tariff, APS does not charge a returning customer a mark-up over the market index rate. Rather, APS will charge the customer a market price until APS is reasonably able to integrate the customer back into its generation planning, at which time the customer may take service at the applicable retail rate.

The $10 per MWh referenced by Mr. Jones appears in a different section of the AG-1 tariff, "Default of the Third Party Generation Provider." This section is not intended for customers returning to standard offer service, as Mr. Jones indicates, but rather customers who are "in between" third-party generation providers. This product is clearly intended as a temporary bridge for a customer whose generation provider has defaulted and is in the process of finding a new market supplier.

Further, Mr. Jones's concerns that UNSE must be "protected" from a returning customer are misplaced. Under my proposal, UNSE experiences no unrecovered revenue deficiency from the buy-through program; thus there is no harm from which UNSE and customers must be "protected." Moreover, if a returning customer is charged a market price that is passed through from UNSE, the Company continues to be held harmless. The $4 per MWh mark-up over the

[18] Rebuttal testimony of Craig A. Jones, p. 50.

market price that I suggested in my direct testimony is intended to provide reasonable compensation to UNSE for undertaking the market transaction for the returning customer. A $20 per MWh penalty is unnecessary and unwarranted.

Q. On what grounds does Mr. Jones disagree with your proposal to clarify that the buy-through program will continue at least until the start of the first rate-effective period of a general rate case following the proposed four-year term?

A. Mr. Jones asserts that AECC "seems to want the best of both worlds" with my recommendation.

Q. What is your response to Mr. Jones on this point?

A. My proposal is merely intended to avoid a "stub period" in which the pilot program terminates prior to its future being considered in a general rate case. Recently, the AG-1 program was extended by the Commission after parties realized that it was scheduled to terminate prior to its future being considered in a general rate case. My proposal is simply intended to line up the terminal date of the initial pilot to the start date of the rate-effective period of the rate case in which the program's future would be decided. This is not attempt to achieve the "best of both worlds," but simply a recommendation in the interest of administrative efficiency.

UNBUNDLED RATE DESIGN

Q. In your direct testimony you challenged UNSE's unbundled rate design for MGS, LGS, and LPS rate schedules. Has UNSE responded in its rebuttal

testimony to your criticism and your recalculation of UNSE's unbundled rates?

A. No. In my direct testimony, I pointed out that UNSE's unbundled rate design is seriously flawed in that the Company is attempting to recover fixed generation-related costs in the Local Delivery component of the demand charge, contrary to the fundamentals of proper unbundled rate design. UNSE has not responded to my criticism, which I believe is irrefutable.

Q. Have you updated your recommended unbundled rate design for the MGS, LGS, and LPS rate schedules to reflect the reduced revenue requirement in your surrebuttal revenue allocation?

A. Yes. My updated unbundled rates are presented in Exhibit KCH-SR-3. My proposed non-fuel revenue requirement for LPS represents a reduction of $126,646 relative to UNSE's (and my) direct testimony to reflect this rate schedule's share of the $4.2 million overall non-fuel revenue requirement reduction accepted by UNSE in its rebuttal filing. I pass this reduction through to the bundled demand charges and energy delivery charges for this rate schedule on a pro rata basis. Within the bundled demand charge, I reflect the reduction on an equal percentage basis between the Demand Delivery and Generation Capacity unbundled charges, as shown on page 1 of the exhibit.

My proposed non-fuel revenue requirement for MGS/LGS represents a reduction of $1,047,288 relative to UNSE's (and my) direct testimony to reflect this group's share of the $4.2 million overall non-fuel revenue requirement reduction accepted by UNSE in its rebuttal filing. I pass this reduction through to the bundled demand charges and energy delivery charges for these rate schedules on a pro rata basis. Within the bundled demand charges, I reflect the reduction on an equal percentage basis between the Demand Delivery and Generation Capacity unbundled charges, as shown on pages 2-3 of the exhibit.

Q. In your direct testimony, you *accepted* the *bundled* demand charges proposed by UNSE, but you proposed significantly different unbundled components. Are you no longer accepting UNSE's bundled demand charges as your starting point for unbundled rates?

A. That is correct. I am no longer accepting UNSE's bundled demand charges as the starting point for unbundled rates because UNSE has changed its revenue allocation unreasonably to the disadvantage of the MSG, LGS, and LPS rate schedules. Even though UNSE has accepted an overall lower revenue requirement in its rebuttal filing, each of these three rate schedules is *worse off* in UNSE's rebuttal filing than in the Company's direct filing. In contrast, I am recommending that each rate schedule be made better off relative to UNSE's direct filing to reflect the $4.2 million reduction in revenue requirement that UNSE has accepted.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

KCH-SR-1

Summary of AECC/Noble Solutions Proposed Surrebuttal Revenue Spread by Customer Class

Line No.	Description (a)	Amount (b)
1	UNSE Direct Filing Requested Revenue Increase =	$22,621,008
2	UNSE Rebuttal Filing Requested Revenue Increase =	$18,457,140
3	UNSE Reduction in Requested Revenue Increase =	($4,163,868)
	AECC/Noble Solutions Recommended Distribution of Reduction in Reqeusted Revenue Increase:	
5	50% Applied to Subsidy Receiving Class =	($2,081,934)
6	50% Applied to Subsidy Paying Classes =	($2,081,934)
7	Reduction of Subsidy Paying Classes Amount Applied to Experimantal Rider 14 Costs[1] =	$908,000
8	Net Reduction Applied to Subsidy Paying Classes =	($1,173,934)

Note 1: This amount would be used to recover any reduction in fixed generation revenues that arise from implementation of the Experimental Rider 14. Any unused funds would be returned to MGS/LGS/LPS customers in a future regulatory proceeding.

AECC/Noble Solutions Recommended Spread of UNSE's Requested Rebuttal Revenue Increase

Line No.		Current Adjusted Test Year Margin Revenue	Percentages for Spreading Revenue Reduction[2]	UNSE As-Filed Base Dollar Change	Spread of Reduction in Revenue Increase	AECC Recommended Base Dollar Change
9	**Residential**	33,425,187	83.4%	$20,556,648	($1,736,785)	$18,819,863
10	**Small General Service**	6,136,594	15.3%	$2,664,336	($318,860)	$2,345,477
11	**Medium/Large General Service**	26,394,695	89.2%	$26,345	($1,047,288)	($1,020,943)
12	**Large Power Service**	3,191,840	10.8%	($771,829)	($126,646)	($898,475)
13	**Lighting**	505,944	1.3%	$75,592	($26,289)	$49,303
14	**Sub-Total**	69,654,260		22,551,092	(3,255,868)	19,295,224
15	**Experimental Rider 14 Reserve**				(908,000)	($908,000)
16	**Total**				(4,163,868)	18,387,224

Note 2: Shaded cell percentages apply to AECC/Noble reduction (see Ln. 5) for subsidy receiving classes. Non-shaded cells percentages apply to AECC/Noble reduction (see Ln. 8) for subsidy paying classes.

Summary of AECC/Noble Solutions Proposed Surrebuttal Revenue Spread by Customer Class

Line No.	Customer Class (a)	UNSE Rebuttal Current Adjusted Test Year Base Revenue (b)	AECC/ Noble Solutions Proposed Base Dollar Change (c)	AECC/ Noble Solutions Proposed Base Percent Change (d)	AECC/ Noble Solutions Net Dollar Change (Year 2) (e)	AECC/ Noble Solutions Net Percent Change (Year 2) (f)
17	**Residential**	$78,169,265	$18,819,863	24.1%	$9,498,015	12.2%
18	**Small General Service**	$12,461,200	$2,345,477	18.8%	$1,438,312	11.5%
19	**Medium/Large General Service**	$56,334,006	($1,020,943)	-1.8%	$310	0.0%
20	**Large Power Service**	$7,446,668	($898,475)	-12.1%	($39,473)	-0.5%
21	**Lighting**	$547,038	$49,303	9.0%	$52,761	9.6%
22	**Sub-Total**	$154,958,178	$19,295,224	12.5%	$10,949,925	7.1%
23	**Experimental Rider 14 Reserve**		($908,000)		($908,000)	
24	**Total**	$154,958,178	$18,387,224	11.9%	$10,041,925	6.5%

KCH-SR-2

Exhibit KCH-SR-2

APS Experimental Rate Rider Schedule AG-1

AVAILABILITY

This experimental rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer customers who have an Aggregated Peak Load of 10 MW or more and are served under Rate Schedules E-34, E-35, E32-L, or E-32 TOU L. An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.

Customers must have interval metering, Advanced Metering Infrastructure, or an alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the customer's applicable rate schedule will apply in addition to this Schedule AG-1, except as modified herein. This rate rider schedule is available for existing AG-1 customers served under the rider as of November 25, 2015 and will remain available until further order of the Arizona Corporation Commission, in accordance with Commission Decision No. 75322. Total program participation shall be limited to 200 MW of customer load, 100 MW of which shall be initially reserved for Customers served under Rate Schedule E-32 L.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-1.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the actual hourly metered load for each Customer for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company shall establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers shall be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule.

AGGREGATION

Eligible customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer shall apply for service under this rate rider schedule.

The Company shall conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer shall select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company shall enter into a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider shall provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company shall provide transmission, delivery and network services to the Customer according to normal retail electric service.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider shall bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company shall bill the customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company shall serve as the scheduling coordinator. The Generation Service Provider shall provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites shall be either scheduled or financially settled.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions in the Company's Open Access Transmission Tariff, Schedule 4. Imbalance Energy will be based on the Generation Service Provider's portfolio of Customer loads.

POWER SUPPLY ADJUSTER AND HEDGE COST TRUE-UP

The customer will be subject to the power supply adjustment – historical component for the first twelve months of service under this rate rider schedule. The customer will also pay for the hedge cost associated with the customer's Standard Generation Service at the time the customer takes service under this rate rider schedule. For the purpose of this rate rider schedule, the Company will determine the applicable pro rata hedge cost based on the market price for hedge costs at the time the customer takes service under this rate rider schedule.

DEFAULT OF THE THIRD PARTY GENERATION PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the customer must notify the Company and select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company shall provide the required power to the customer, which will be charged at the Dow Jones Electricity Palo Verde Hourly Index price for the power delivery date plus $10 per MWh. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule without charge if: (1) they provide six months notice (or longer) to the Company; or (2) if the Commission terminates the program. Absent one of these conditions, the Company will provide the customer with generation service at the market index rate provided in the Company's Open Access Transmission Tariff until the Company is reasonably able to integrate the customer back into their generation planning and provide power at the applicable retail rate schedule. This transition will be at the Company's determination but no longer than 1 year. The returning customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:

1. The generation charges will not apply;
2. Adjustment Schedule PSA-1will not apply, except that the Historical Component will apply for the first twelve months of service under this rate rider schedule;
3. Adjustment Schedule EIS will not apply; and
4. The applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder shall be applied to the customer's bill.

Schedule AG-1 charges determined and billed by the Company include:

1. A monthly management fee of $0.00060 per kWh applied to the customer's metered kWh;
2. A monthly reserve capacity charge applied to 15% of the customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L) at the Company's applicable cost-based rate filed at the Federal Energy Regulatory Commission and revised from time to time, which is currently $6.985 per kW month;
3. An initial charge or credit for fuel hedging costs, as described herein;
4. Returning Customer charge, where applicable, as described herein;
5. Generation Service Provider Default charge, where applicable, as described herein.

Schedule AG-1 Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges shall be charged at a rate within the minimum and maximum limits as follows:

   a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.
   b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price shall be the generation rate of the Customers applicable retail schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.
   c. Losses from the delivery point to the Customer's meters and any charges assessed by the Company on the Customer, including charges for transmission and distribution, Capacity Reservation Charge, the Management Fee, Imbalance Service charges, PSA balance and hedging costs, and Returning Customer Charges, shall not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.

2. Imbalance Service charges shall be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider shall be for not less than one year and shall not exceed four years.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules

KCH-SR-3

AECC/Noble Solutions' Recommended Unbundled LPS & LPS-TOU Rates
(at UNSE's Rebuttal Revenue Requirement)

Line No.	Description	UNSE Proposed Bundled Rates (Rebuttal)[1]	AECC/ Noble Solutions Recommended Rates (Direct)	AECC/ Noble Solutions Recommended Rates (Rebuttal)
1	Basic Service Charge Components ($/Cust./Mo.):			
2	Meter Services		$145.57	$145.57
3	Meter Reading		$101.86	$101.86
4	Billing & Collection		$451.63	$451.63
5	Customer Delivery		$500.94	$500.94
6	Total	$1,500.00	$1,200.00	$1,200.00
7	Demand Charge Components ($/kW):			
8	Local Delivery		$0.29	$0.26
9	Generation Capacity		$8.61	$7.93
10	Transmission		$3.58	$3.57
11	Total	$13.00	$12.48	$11.76
12	Energy Charge Components ($/kWh):			
13	Local Delivery	$0.000500	$0.000520	$0.000489
14	Power Supply Charges ($/kWh):			
15	Base Power Supply (LPS)	$0.049332	$0.048410	$0.049332
16	Base Power Supply Summer On-Peak - (LPS-TOU)	$0.125155	$0.122510	$0.125155
17	Base Power Supply Summer Off-Peak - (LPS-TOU)	$0.033410	$0.032110	$0.033410
18	Base Power Supply Winter On-Peak - (LPS-TOU)	$0.092110	$0.092110	$0.092110
19	Base Power Supply Winter Off-Peak - (LPS-TOU)	$0.030410	$0.030910	$0.030410
20	PPFAC (%) (see Rider-1 for current rate)	Varies	Varies	Varies

Notes:
1. Data Source: UNSE Exhibit CAJ-R-4, Schedule H-3, p. 6 of 8.

AECC/Noble Solutions' Recommended Unbundled LGS, LGS-TOU & LGS-TOU-S Rates (at UNSE's Rebuttal Revenue Requirement)

Line No.	Description	UNSE Proposed Bundled Rates (Rebuttal)[1]	AECC/ Noble Solutions Recommended Rates (Direct)	AECC/ Noble Solutions Recommended Rates (Rebuttal)
1	Basic Service Charge Components ($/Cust./Mo.):			
2	Meter Services		$31.32	$31.32
3	Meter Reading		$5.01	$5.01
4	Billing & Collection		$22.15	$22.15
5	Customer Delivery		$241.52	$241.52
6	Total	$300.00	$300.00	$300.00
7	Demand Charge Components ($/kW):			
8	Demand Delivery		$0.96	$0.91
9	Generation Capacity		$9.70	$9.20
10	Transmission		$2.30	$2.30
11	Total	$13.35	$12.96	$12.41
12	Energy Charge Components ($/kWh):			
13	Local Delivery	$0.005470	$0.005400	$0.005167
14	Power Supply Charges ($/kWh):			
15	Base Power Supply (LGS)	$0.053290	$0.048400	$0.053290
16	Base Power Supply Summer On-Peak - (LGS-TOU)	$0.143771	$0.145510	$0.143771
17	Base Power Supply Summer Off-Peak - (LGS-TOU)	$0.038600	$0.034510	$0.038600
18	Base Power Supply Winter On-Peak - (LGS-TOU)	$0.139880	$0.124510	$0.139880
19	Base Power Supply Winter Off-Peak - (LGS-TOU)	$0.034927	$0.032910	$0.034927
20	Base Power Supply Summer On-Peak - (LGS-TOU-S)	$0.148471	$0.150210	$0.148471
21	Base Power Supply Summer Off-Peak - (LGS-TOU-S)	$0.043300	$0.039210	$0.043300
22	Base Power Supply Winter On-Peak - (LGS-TOU-S)	$0.144580	$0.129210	$0.144580
23	Base Power Supply Winter Off-Peak - (LGS-TOU-S)	$0.039627	$0.037610	$0.039627
24	PPFAC (%) (see Rider-1 for current rate)	Varies	Varies	Varies

Notes:
1. Data Source: UNSE Exhibit CAJ-R-4, Schedule H-3, p. 6 & 7 of 8.

AECC/Noble Solutions' Recommended Unbundled MGS, MGS-TOU & MGS-TOU-S Rates (at UNSE's Rebuttal Revenue Requirement)

Line No.	Description	UNSE Proposed Bundled Rates (Rebuttal)[1]	AECC/ Noble Solutions Recommended Rates (Direct)	AECC/ Noble Solutions Recommended Rates (Rebuttal)
1	Basic Service Charge Components ($/Cust./Mo.):			
2	Meter Services		$10.44	$10.44
3	Meter Reading		$1.67	$1.67
4	Billing & Collection		$7.38	$7.38
5	Customer Delivery		$80.51	$80.51
6	Total	$100.00	$100.00	$100.00
7	Demand Charge Components ($/kW):			
8	Demand Delivery		$2.26	$2.16
9	Generation Capacity		$8.40	$8.04
10	Transmission		$2.30	$2.30
11	Total	$13.95	$12.96	$12.50
12	Energy Charge Components ($/kWh):			
13	Local Delivery	$0.005500	$0.005500	$0.005263
14	Power Supply Charges ($/kWh):			
15	Base Power Supply (MGS)	$0.053290	$0.048440	$0.053290
16	Base Power Supply Summer On-Peak - (MGS-TOU)	$0.114886	$0.109900	$0.114886
17	Base Power Supply Summer Off-Peak - (MGS-TOU)	$0.033500	$0.033500	$0.033500
18	Base Power Supply Winter On-Peak - (MGS-TOU)	$0.101047	$0.089900	$0.101047
19	Base Power Supply Winter Off-Peak - (MGS-TOU)	$0.031690	$0.031600	$0.031690
20	Base Power Supply Summer On-Peak - (MGS-TOU-S)	$0.120586	$0.115600	$0.120586
21	Base Power Supply Summer Off-Peak - (MGS-TOU-S)	$0.039200	$0.039200	$0.039200
22	Base Power Supply Winter On-Peak - (MGS-TOU-S)	$0.106747	$0.095600	$0.106747
23	Base Power Supply Winter Off-Peak - (MGS-TOU-S)	$0.037390	$0.037300	$0.037390
24	PPFAC (%) (see Rider-1 for current rate)	Varies	Varies	Varies

Notes:
1. Data Source: UNSE Exhibit CAJ-R-4, Schedule H-3, p. 5 & 7 of 8.