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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 DIRECT TESTIMONY (RATE DESIGN) AND EXHIBITS OF 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 Direct Testimony (Rate Design) and Exhibits of Kevin C. Higgins on behalf of AECC and Noble in the above captioned Docket.

RESPECTFULLY SUBMITTED this 9th day of December, 2015.

FENNEMORE CRAIG, P.C.

By: ______________________

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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

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport Minerals Corporation,

Arizonans for Electric Choice & Competition and

Noble Americas Energy Solutions LLC

Rate Design

December 9, 2015

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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DIRECT 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. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport Minerals Corporation, Arizonans for Electric Choice and Competition ("AECC") and Noble Americas Energy Solutions LLC ("Noble Solutions"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1] Noble Solutions is a retail energy supplier that serves over 15,000 commercial and industrial end-use customers in 16 states, the District of Columbia, and Baja California, Mexico, and supplies power to Arizona Public Service Company ("APS") that serves Experimental Rate Rider AG-1 ("AG-1") customers on the APS system.

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the

[1] Henceforth in this testimony, Freeport Minerals Corporation and AECC collectively will be referred to as "AECC."

University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before the Arizona Corporation Commission ("Commission") in other dockets?

A. Yes. I have testified in approximately twenty proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on APS 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the

[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.

Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS 2006 rate case (2006),[13] TEP's request to amend Decision No. 62103 (2007),[14] the TEP 2007 rate case (2008),[15] the APS 2008 rate case (2008),[16] the APS 2011 rate case (2011-12),[17] the TEP 2011 Energy Efficiency Plan (2012),[18] the TEP 2012 rate case (2012),[19] and the APS Four Corners Rate Rider proceeding (2014).[20]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 180 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission ("FERC").

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8 Docket No. E-00000A-01-0630.
9 Docket No. E-01345A-03-0437.
10 Docket No. E-01461A-04-0607.
11 Docket No. E-01933A-04-0408.
12 Docket No. E-01345A-06-0009.
13 Docket No. E-01345A-05-0816.
14 Docket No. E-01933A-05-0650.
15 Docket No. E-01933A-07-0402.
16 Docket No. E-01345A-08-0172.
17 Docket No. E-01345A-11-0224.
18 Docket No. E-01933A-11-0055.
19 Docket No. E-01933A-12-0291.
20 Docket No. E-01345A-11-0224.

OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My testimony addresses the following topics in response to the general rate case filing made by UNS Electric, Inc. ("UNSE" or the "Company"): (1) rate spread, (2) cost of service, (3) the buy-through tariff presented by the Company (Experimental Rider 14, Alternative Generation Service), and (4) unbundled rate design for larger commercial and industrial customers.

Relative to the wide scope of this general rate proceeding, my testimony is concentrated on a limited number of issues. Absence of comment on my part regarding a particular issue does not signify support (or opposition) toward the Company's filing with respect to a non-discussed issue.

Q. What are your primary conclusions and recommendations?

A. I offer the primary conclusions and recommendations:

(1) UNSE's proposed rate spread, or revenue apportionment, among customer classes is generally reasonable. Even though UNSE's proposal results in considerable cross subsidies remaining in rates, the Company is taking a step in the direction of achieving a better alignment of class revenue requirement and class cost of service while remaining consistent with the principles of gradualism.

(2) If a reduction to UNSE's proposed revenue requirement is approved by the Commission I recommend that it be apportioned 50% to the subsidy-paying classes (in proportion to their respective base revenue requirements) and 50% to the subsidy receiving classes (in proportion to their respective base revenue requirements). Further, I 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, as discussed later in my testimony.

(3) I recommend adoption of the Average and Excess Demand method used by UNSE to allocate production cost, as this method is both well-accepted and fundamentally reasonable.

(4) I recommend adoption of a buy-through program that is as similar as reasonably possible to the AG-1 program approved for APS. A buy-through program provides commercial, industrial, and public sector customers with the opportunity to gain experience with market transactions and potentially reduce their energy costs, which enhances the economic development climate of the service territory and in the state generally. I recommend adopting some of the features of the buy-through program presented by UNSE, but modifying other features to make the program open to a wider variety of customers and to make it a more viable offering. Specifically, I recommend changes to program eligibility, pricing, terms for return to standard generation service, and the mechanics of fixed generation cost recovery. In particular:

(a) I recommend retaining the proposed 10 MW cap on participation proposed by UNSE, but broadening the range of eligible customers by allowing customers to participate with a minimum load size of 1 MW (peak demand) and allowing aggregation of smaller loads in the Medium and Large General Service classes owned by the same corporate entity to achieve that 1 MW threshold. I recommend that the term of the program be clarified to indicate that the buy-through program will continue at least until the start of the first rate-effective period (following a general rate case) occurring no less than four years from the starting date of the buy-through program.

(b) The monthly management fee of $0.004/kWh for buy-through service proposed by UNSE is unreasonable and should be reduced to $0.0006/kWh, which is the management fee charged by APS for AG-1 service.

(c) Under the UNSE program, for the first twelve months of service under the rider, the generation-related component of the Demand Charge would continue to apply to 100% of the customer's billed demand, with this proportion decreasing to 25% after twelve months. While some assignment of cost for generation reserves may be appropriate, the UNSE proposal goes well beyond such a threshold and is more comparable to a stranded cost charge. The stranded cost approach should be rejected unless the customers are being provided with an opportunity to transition permanently to market pricing. Absent such an option, the going-forward charges for generation-related services 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, which is based on UNSE's planning reserve margin and is comparable to the AG-1 reserve capacity charge levied by APS.

In addition, I recommend 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 – 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.

(d) 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. While I agree that this general approach is reasonable, I believe the proposed $20 per MWh mark-up is excessive and should be eliminated or significantly reduced to no greater than $4 per MWh.

(5) UNSE's unbundled rate design is seriously flawed in that the Company is improperly attempting to recover fixed generation-related costs in the unbundled Local Delivery component of the demand charge, contrary to the fundamentals of proper unbundled rate design. For this reason I recommend that UNSE's proposed relationship between delivery demand charges and generation capacity demand charges in its unbundled tariff for Medium General Service, Large General Service, and Large Power Service be rejected. Instead, I recommend that the unbundled rate design presented in Exhibit KCH-1 attached to my testimony should be adopted (at the UNSE revenue requirement for these classes).

RATE SPREAD

Q. Please describe the rate increase and spread of rates proposed by UNSE.

A. UNSE is proposing a base rate increase of $22.6 million, which is an average base rate increase of 11.9%. However, $4.3 million of this base rate increase consists of the transfer into base rates of revenues currently recovered in the Transmission Cost Adjustor ("TCA"). In addition, a large portion of the proposed increase is offset by a $14.9 million reduction in the Base Fuel Rate. When these offsets are netted out, the net revenue increase proposed by UNSE is $3.6 million, or 2.5%. The net increase to the UNSE customer classes is shown in Table KCH-1 below.

Table KCH-1

Summary of UNSE Proposed Revenue Spread by Customer Class

Customer Class	Current Adjusted Test Year Base Revenue	UNSE Proposed Base Dollar Change	UNSE Proposed Base Percent Change	UNSE Proposed Net Dollar Change	UNSE Proposed Net Percent Change
Residential	$73,653,026	$20,556,648	27.9%	$7,507,747	10.2%
Small General Service	$11,905,151	$2,664,336	22.4%	$1,185,904	10.0%
Medium/Large General Service	$53,699,953	$26,345	0.0%	($3,485,442)	-6.5%
Large Power Service	$7,375,505	($771,829)	-10.5%	($1,672,387)	-22.7%
Lighting	$543,010	$75,592	13.9%	$75,046	13.8%
Total	$147,176,645	$22,551,092	15.3%	$3,610,868	2.5%

Q. What are your observations regarding UNSE's proposed rate spread?

A. UNSE's proposed rate spread, or revenue apportionment, shows a dispersed rate change by customer class, with some classes receiving increases in the range of 10.0% – 13.8%, with others receiving net rate decreases.

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining rate spread it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. How does the spread of rates proposed by UNSE relate to class recovery of cost of service?

The final rates proposed by UNSE contain considerable interclass subsidies, which are summarized in Table KCH-2, below. The largest subsidy goes to the Residential class, which under-recovers its allocated costs by $8.2 million at UNSE's proposed revenue requirement. Small General Service also receives a subsidy of just over $900 thousand. The large majority of the subsidy is paid by the Medium General Service ("MGS") and Large General Service ("LGS") classes, which together over-recover their costs by $8.2 million. In addition, Large Power Service ("LPS") pays a subsidy of nearly $900 thousand.

Table KCH-2

Subsidies Included in UNSE's Proposed Revenue Spread by Customer Class

Customer Class	Current Adjusted Test Year Base Revenue	Revenue Change Required to Achieve COS	UNSE Proposed Base Dollar Change	UNSE Proposed Subsidy (Paid)/ Subsidy Received
Residential	$73,653,026	$28,730,078	$20,556,648	$8,173,429
Small General Service	$11,905,151	$3,578,296	$2,664,336	$913,959
Medium/Large General Service	$53,699,953	($8,183,024)	$26,345	($8,209,369)
Large Power Service	$7,375,505	($1,667,982)	($771,829)	($896,153)
Lighting	$543,010	$93,725	$75,592	$18,134
Total	$147,176,645	$22,551,092	$22,551,092	$0

Q. **What is your assessment of UNSE's proposed rate spread?**

A. I believe that UNSE's proposed rate spread is generally reasonable, even though it results in considerable cross subsidies remaining in rates. UNSE is proposing to increase the rates of those classes that are relatively under-recovering their allocated costs and to reduce the rates of those classes that are relatively over-recovering their costs. In proposing these actions, the Company is taking a step in the direction of achieving a better alignment of class revenue requirement and class cost of service while remaining consistent with the principles of gradualism.

Q. **How should UNSE's proposed rate spread be modified if the approved revenue requirement is reduced from what the Company has requested?**

A. It is highly plausible that some reduction from what UNSE has requested will be required. For example, Staff has proposed that UNSE's proposed revenue requirement increase be reduced by \$4.5 million[21] and RUCO is recommending a reduction of \$10.35 million.[22] If a reduction to UNSE's proposed revenue requirement is approved by the Commission I recommend that it be apportioned 50% to the subsidy-paying classes (in proportion to their respective base revenue requirements) and 50% to the subsidy receiving classes (in proportion to their respective base revenue requirements). Further, I 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. The mechanism for doing so is discussed later in my testimony.

COST OF SERVICE

Q. What method has UNSE used for allocating production costs to customer classes?

A. UNSE uses the Average and Excess Demand - 4CP method. As described in the Electric Utility Cost Allocation Manual published by the National Association Regulatory Utility Commissioners ("NARUC"), the Average and Excess Demand method uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor.[23] The cost of capacity above average demand is then allocated in proportion to each class's <u>excess</u> demand, where excess demand is measured as the *difference* between each

[21] See direct testimony of Donna H. Mullinax, p. 8.
[22] See direct testimony of Jeffrey M. Michlik, Schedule JMM-1.
[23] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

class's individual peak demand[24] and its average demand. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is assigned to the users who create the need for the additional capacity. The 4CP variant of the Average and Excess method used by UNSE utilizes each class's demand during the utility's four highest monthly coincident peaks (or "4CP") to measure excess demand, whereas the conventional version uses class non-coincident peak for this purpose. The 4CP variant of Average and Excess is also used in Colorado and Texas.

Q. Do you have any comments regarding UNSE's use of the Average and Excess Demand method to allocate production costs?

A. Yes. I believe the use of the Average and Excess Demand method is reasonable and should be adopted for cost allocation in this case. The Average and Excess Demand method is a well-accepted method for allocating production costs. It has been used by APS for many years and I am aware of this method being approved by regulatory commissions in Colorado, New Mexico, Texas, Virginia, and Kentucky.

Q. Why do you believe the Average and Excess Demand method produces reasonable results?

A. The Average and Excess Demand method addresses a fundamentally important question in production cost allocation: once we've accounted for the capacity needed to serve the average demand on the system, how should we fairly assign the responsibility for the *additional* (or excess) capacity that is needed to

[24] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

meet the various capacity requirements put on the system by each customer class? The Average and Excess Demand method makes an objective and reasonable attempt to answer this question.

BUY-THROUGH TARIFF

Q. Please provide an overview of the buy-through tariff presented by UNSE in this proceeding.

A. UNSE has submitted a buy-through tariff in this proceeding pursuant to the settlement agreement approved by the Commission in the proceeding concerning the acquisition of UNS Energy by Fortis, Inc.[25] However, UNSE is opposed to the implementation of this tariff, contending that it will result in costs being passed on to the remaining customers, while allowing certain large customers to "cherry pick" currently available capacity in the market.[26]

As described in the Direct Testimony of Craig A. Jones, Experimental Rider 14, Alternative Generation Service, is designed as an optional program to provide an alternative generation arrangement for participating LPS customers.

Q. How would this alternative generation arrangement operate?

A. According to Mr. Jones' direct testimony, the participating customer would select a wholesale generation service provider with whom to contract to sell power to the Company on the customer's behalf. The power would be delivered to the Company's point(s) of delivery, and the Company would provide

[25] Docket Nos. E-04230A-14-0011 and E-01933A-14-0011, Settlement Agreement Attachment A, Condition 31, approved by the Commission in Decision No. 74689.
[26] Direct Testimony of Craig A. Jones, p. 56.

transmission and delivery services under the customer's current retail rate schedule.[27]

The Company would purchase and manage this generation for the customer for a management fee of $0.0040 per kWh.[28] The Company would also serve as the scheduling coordinator and would provide Imbalance Service according to the Company's Open Access Transmission Tariff, with Imbalance Energy based on the generation service provider's portfolio of customer loads. Customers would be charged for Imbalance Service at a rate greater than $0.00 per kWh and less than or equal to the rate charged to the generation service provider by UNSE. The Company would bill the customer for the generation service provider's charged amounts for Generation Service and Imbalance Service.[29]

The customer would also be subject to all of the charges and adjustments in its retail rate schedule with the exception of the Base Power Charge, the unbundled generation-related components of the Demand Charge and the Delivery Services Energy Charge,[30] and the Purchased Power and Fuel Adjustment Clause ("PPFAC"). However, for the first twelve months of service under the rider, the generation-related component of the Demand Charge would continue to apply to 100% of the customer's billed demand, with this proportion

[27] Id., pp. 56-57.
[28] Exhibit CAJ-3, (Experimental Rider-14 proposed tariff), Original Sheet No. 714-2. Note: the Direct Testimony of Craig A. Jones contained a typographical error of $0.0060/kWh. See UNSE Response to STF 2.116.
[29] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet No. 714-2.
[30] While the proposed tariff indicates that buy-through customers would be exempt from the unbundled Generation component in the Delivery Services Energy Charge, there *is no such charge* under the proposed tariff, although the current tariff does have such a component. See also Footnote 31.

decreasing to 25% after twelve months.[31] The customer would also be subject to the historical component of the PPFAC for the first twelve months. In addition, the customer would be responsible for the hedging cost associated with the customer's standard generation service at the time the customer takes service under the rider.[32]

Q. Please describe the buy-through program size, eligibility requirements, and program term as designed by UNSE.

A. The total program would be limited to 10 MW of peak load, and would be available to customers in the LPS and LPS-TOU rate classes with peak demands of 2,500 kW or more. Eligible customers could apply during the initial enrollment period, and if the total MW of peak load from the applications exceeded the program maximum, customers would be selected through a lottery process to be developed by UNSE.[33] The Company proposes that the program be available for no more than four years from the effective date of new rates in this docket.[34]

Q. What would happen if the generation service provider defaults or the customer wants to return to standard generation service?

A. If the generation service provider cannot meet its contractual obligations, the customer must notify the Company and select another generation service

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[31] Note: The proposed tariff also indicates these provisions would apply to the unbundled Generation component of the Energy Charge for Delivery Services. However, as I indicate in Footnote 30, there is no such unbundled Generation component in the Delivery Services Energy Charge under the proposed tariff, although the current tariff does have such a component. Therefore, for purposes of this discussion, I will treat UNSE's proposal to recover all or a portion of the unbundled Generation component of the Energy Charge for Delivery Services from buy-through customers as moot.
[32] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet Nos. 714-1 through 714-2.
[33] Direct Testimony of Craig A. Jones, p. 57, lns. 14-23.
[34] Id., p. 56, lns. 21-22.

provider within 60 days. The Company would supply power to the customer prior to execution of the new power contract at the Dow Jones Electricity Palo Verde Daily Index price plus $20 per MWh.

If the customer wishes to return to standard generation service without providing one year notice to the Company and prior to program termination, the Company would supply power to the customer at the Dow Jones Electricity Palo Verde Daily Index price plus $20 per MWh until the Company is able to integrate the customer back into its generation planning and provide power at standard retail rates.[35]

Q. How does UNSE propose to recover the remaining fixed generation costs that are not recovered from buy-through customers?

A. As I explained above, according to the Company's proposal, subsequent to the first year of service under the rider, buy-through customers would not be subject to the generation-related component of the Demand Charge for 75% of the buy-through customers' billing demands.[36] The Company proposes that any "lost revenues" resulting from the buy-through program should be recovered through the Lost Fixed Cost Recovery Mechanism ("LFCR") and paid for by all the customers subject to this charge.[37]

Q. What is your assessment of the buy-through program presented by UNSE?

A. A buy-through program provides customers with the opportunity to gain experience with market transactions and potentially reduce their energy costs, thereby enhancing the economic development climate of the UNSE service

[35] Exhibit CAJ-3 (Experimental Rider-14 proposed tariff), Original Sheet No. 714-3.
[36] See also Footnotes 30 and 31.
[37] Direct Testimony of Craig A. Jones, p. 59, lns. 1-7.

territory and of the state generally. I recommend adoption of a buy-through program that is as similar as reasonably possible to the AG-1 program approved for APS. This would mean adopting some of the features of the buy-through program presented by UNSE, but modifying other features to make the program open to a wider variety of customers and to make it a more viable option. Specifically, I recommend changes to program eligibility, pricing, terms of return to standard generation service, and the mechanics of fixed generation cost recovery. I also recommend a clarification to the program term.

Q. What is your recommended clarification to the program term?

A. I do not disagree with UNSE's proposal to target a four-year period for the term of the program. However, I believe it is important for consideration of program extension or modifications to be considered in the context of a future general rate case prior to the termination of the program. Therefore I recommend that the term of the program be restated to indicate that the buy-through program will continue at least until the start of the first rate-effective period (following a general rate case) occurring no less than four years from the starting date of the buy-through program.

Q. Please describe the changes to program eligibility that you are recommending.

A. While I would retain the proposed 10 MW cap on participation proposed by UNSE, I recommend broadening the range of the customers that would be eligible to participate. Specifically, I recommend allowing customers to participate with a minimum load size of 1 MW (peak demand) and allowing aggregation of smaller loads in the MGS/LGS classes owned by the same corporate entity to achieve that 1 MW threshold. Each single site aggregated to reach the 1 MW threshold should have experienced a billing demand of at least 200 kW in the past year to be eligible.

Q. Why do you recommend broadening the range of eligible customers?

A. The APS buy-through program reserved 50% of the initial capacity for customers on Schedule 32-L, which roughly corresponds to the UNSE MGS and LGS classes. The APS program allows Schedule 32-L (and in some cases smaller) customers to aggregate their single site loads to achieve the 10 MW minimum size required to participate in the AG-1 program. 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 similarly-situated UNSE customers.

Q. You state that the APS AG-1 program allows aggregation but requires a 10 MW minimum aggregated load size. Why are you recommending a 1 MW aggregated load size for UNSE?

A. APS is a much larger service territory than UNSE, so there is greater potential to aggregate smaller loads up to a 10 MW threshold. Indeed, the APS non-residential retail load is about 20 times larger than that of UNSE. My recommended 1 MW threshold for aggregated loads in the UNSE service territory simply scales back the APS aggregate threshold to take into account the smaller UNSE service territory, while balancing the need for sufficient critical mass for each participant in this experimental program.

Q. Are there aspects of buy-through program pricing proposed by UNSE that you agree are reasonable?

A. Yes. UNSE's proposal that the buy-through customer be subject to the historical component of the PPFAC for one year is reasonable because it relates to service the customer would have received prior to switching to buy-through service. In addition, UNSE's proposal to assign a pro rata share of previously-incurred hedging costs is reasonable in *concept.* I note, however, that the reasonableness of the specific calculations that UNSE intends to apply has yet to be demonstrated.

Q. What changes to buy-through program pricing are you recommending?

A. I am recommending changes to the proposed monthly management fee as well as to the continuation of certain generation demand charges proposed by UNSE.

Q. What change to the monthly management fee are you recommending?

A. UNSE is proposing a monthly management fee of $0.004/kWh for buy-through service. While I agree that some management fee cost is appropriate, the fee proposed by UNSE is more than six times greater than the $0.0006/kWh management fee charged by APS for AG-1 service. It thus strikes me as unreasonable and exorbitant. A management fee of $0.0006/kWh, comparable to the AG-1 charge, is more reasonable.

Q. What changes to UNSE's proposed generation charges for buy-through customers are you recommending?

A. As I discussed above, under the UNSE program, the generation-related component of the Demand Charge would continue to apply to 100% of the buy-through customer's billed demand for the first twelve months, with this proportion decreasing to 25% for the subsequent three years. Ostensibly, these charges are for reserve capacity. While some assignment of cost for reserves capacity may be appropriate, the UNSE proposal goes well beyond such a threshold.

The proper basis for charging for reserve capacity is the utility's planning reserve margin. A planning reserve margin is used in the resource planning process to compensate for uncertainty surrounding future load forecast changes and resource contingencies such as generation or transmission forced outages. The planning reserve margin is calculated as the amount of firm peak resource capacity in excess of projected retail demand as a percentage of total demand. The planning reserve margin used by UNSE in the Company's Integrated Resource Plan ("IRP") is 15%.[38]

Significantly, under the AG-1 tariff, the monthly reserve capacity charge is applied to 15% of the customer's billed demand priced at APS's cost-based rate for generation capacity filed at FERC, consistent with APS's planning reserve margin of 15%.[39]

UNSE's proposal to retain fixed generation charges for services that the buy-through customer would not utilize are pricing features that do not exist in the APS AG-1 program. I recommend that these charges not be introduced into the UNSE buy-through program. Instead, the going-forward charges for generation-related services 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 for the customer's rate schedule. This pricing

[38] See UNSE 2014 IRP, p. 33.
[39] See APS 2014 IRP, p. 93.

approach ties the charge for reserve capacity to UNSE's planning reserve margin in the Company's IRP and is comparable to APS's AG-1 charge for reserve capacity.

Q. Why do you recommend against adoption of UNSE's generation pricing proposal?

A. As I stated above, UNSE's proposed generation charges are for services (e.g., fixed generation cost) that the buy-through customer would not utilize while acquiring market power through UNSE. The charges proposed by UNSE beyond a 15% charge for reserve capacity are in effect stranded cost charges that are typically levied by utilities when direct access service is being offered. A critical distinction with respect to retail choice programs is that in exchange for the customer's payment of stranded cost charges for a period of time (e.g., five years) the customer is allowed to migrate *permanently* to market participation with no further stranded cost obligation. That is not the case with the proposed buy-through program. When the term of the customer's participation in the buy-through program has expired the customer is presumed to have no continued right to market procurement unless the program is extended and the customer is able to regain a slot. In short, if the participating customer is required to pay a stranded cost charge as proposed by UNSE, then a more permanent shopping option, accompanied by a timetable for cessation of stranded cost obligations, should be on offer.

In addition, the Year 1 charge of 100% of fixed generation costs proposed by UNSE strikes me as a being a potentially significant barrier to participation, as the buy-through participant would have to pay both this charge and purchase 100% of its power in the marketplace.

Q. If the pricing features proposed by UNSE are not adopted, how should the Company's revenue deficiency associated with the buy-through program be recovered?

A. In my discussion of rate spread, above, I recommended that the first $908 thousand of any revenue requirement reduction apportioned to the subsidy-paying classes be used to support the Experimental Rider 14 buy-through program. The subsidy-paying classes (MGS, LGS, and LPS) are also the classes that I recommend be eligible for the buy-through program.

This funding mechanism would work as follows. The first $908 thousand of revenue requirement reduction apportioned to MGS, LGS and LPS (collectively) would <u>not</u> be applied to a change in rates per se. Rather, this $908 thousand would be used to absorb UNSE's revenue deficiency that is attributed to the reduction in fixed generation revenues from buy-through customers. In this way, 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.

Q. Why is it reasonable to recover the fixed generation costs from the classes eligible to participate in the program rather than by directly assigning the cost recovery to the buy-through participants?

A. As I discussed previously, directly assigning stranded cost charges might be appropriate if participants were being offered a more permanent shopping option. Further, the opportunity to participate in the program provides a potential value-added option for the members of the eligible classes. It strikes me as more reasonable to recover the fixed generation costs of the buy-through program through a foregone rate reduction from the eligible classes rather than relying on a combination of direct assignment to participants and the LFCR mechanism as proposed by UNSE.

Q. Why are you estimating that the revenue required to fund the buy-through program is around $908 thousand per year?

A. UNSE has estimated that the revenue required for a 10 MW program under its proposed parameters is $331,200 per year for Years 2 through 4.[40] However, that estimate assumes a 25% direct assignment of fixed generation costs to participants in Years 2 through 4. In addition, as I will discuss in the next section of my testimony, UNSE's unbundled charge for fixed generation cost is grossly understated as a share of the Company's charges for fixed cost recovery (and its unbundled delivery demand charge is grossly overstated). Correcting this rate design relationship and reducing the 25% direct assignment charge to a 15% reserve capacity charge will increase the revenue requirement to support the program to around $908 thousand per year, assuming fully-subscribed participation.[41]

To the extent that program initiation is delayed and does not coincide with the start of the rate-effective period in this case, then there should be a downward adjustment to the annual imputed cost of the program prorated over the planned

[40] See UNSE Response to Staff Data Request 2.118.

[41] If all buy-through participants are in the LPS class, the cost would be $878 thousand per year. Similarly, if all buy-through participants are in LGS class the cost would be $989 thousand per year and if all buy-through participants are in the MGS class the cost would be $857 thousand per year. My estimate of $908 thousand is the simple average of this range.

four-year term of the program, to account for the over-recovery of revenues from eligible classes during the delayed start-up.

Q. What do you recommend if the buy-through program is not fully subscribed?

A. If the buy-through program is not fully subscribed then the revenues set aside to fund the program and which turn out to be superfluous should be deferred and returned to the eligible classes through a suitable rate mechanism, perhaps through the PPFAC.

Q. What do you recommend in the event that the Commission does not order a revenue requirement reduction relative to UNSE's proposed revenue increase that is sufficient to fund the buy-through requirements?

A. In that event, although it appears unlikely, I recommend that the program costs be funded out of the revenue requirement reductions proposed by UNSE for the eligible classes.

Q. Please explain your proposed change to the return to general service provision.

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. While I agree that this general approach is reasonable, I believe the proposed $20 per MWh mark-up is excessive. In comparison, 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 believe the $20per MWh mark-up proposed by UNSE should be eliminated or significantly reduced to no greater than $4 per MWh.

Q. Are you aware of whether any AG-1 customers have sought to return to APS standard generation service prior to the planned term of the AG-1 program?

A. To the best of my knowledge, no AG-1 customers have sought to return to APS standard generation service prior to the planned term of the AG-1 program.

UNBUNDLED RATE DESIGN

Q. What aspects of UNSE's proposed rate design are you addressing in your testimony?

A. My testimony addresses the rate design for UNSE's *unbundled* demand charges for the MGS, LGS, and LPS classes. My absence of comment on other aspects of UNSE's rate design should not be interpreted as support for (or opposition to) UNSE's proposed rate design generally.

Q. By way of background, please explain the significance of an unbundled tariff.

A. An unbundled tariff is one in which utility rates are separated according to function, in particular, generation, transmission, and distribution (or delivery service). The Commission's rules carefully prescribe the requirements for filing an unbundled tariff.[42] The fundamental requirement in any well-designed unbundled tariff is that each unbundled component should only recover costs associated with its specific function. That is, the unbundled delivery service

[42] See AAC R14-2-1606.C.2.

charge should only recover delivery-services-related costs (and not generation costs), the unbundled generation charge should only recover generation-related costs, and the unbundled transmission charge should only recover transmission-related costs.

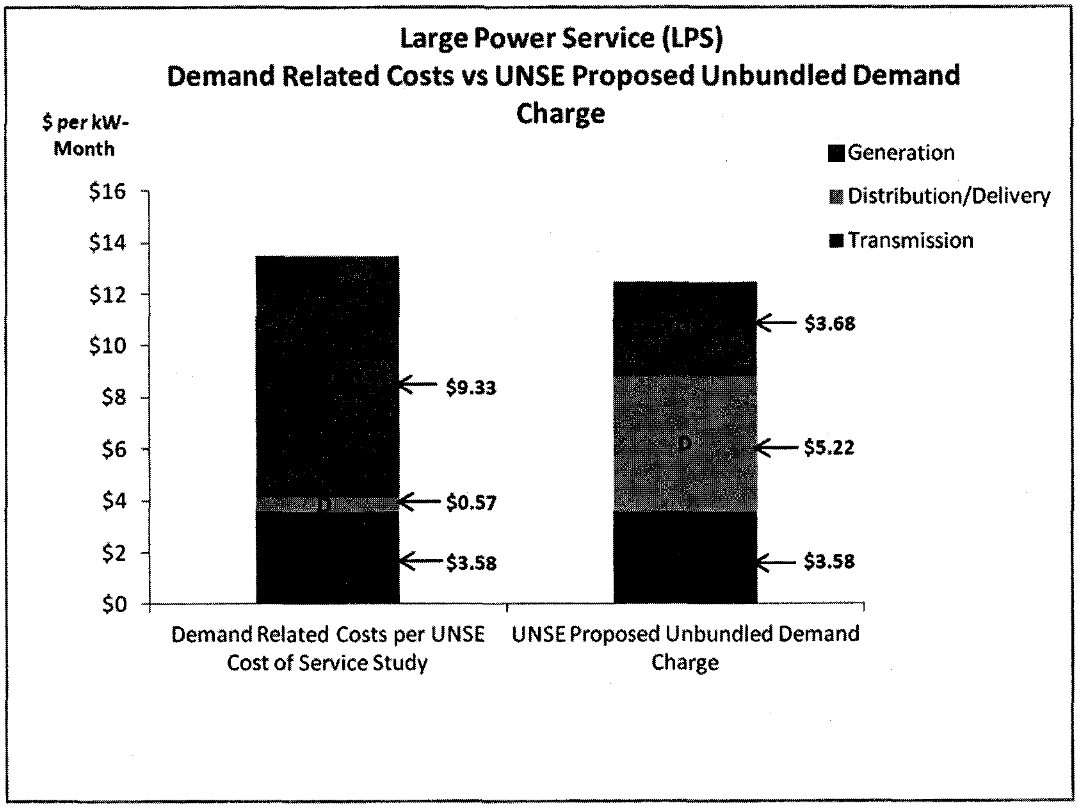
A well-designed unbundled tariff is essential to implement a buy-through program because customers in such a program purchase their generation service from third parties and thus the rates they pay the utility must accurately distinguish the avoidable generation costs from the other components in the rate schedule.

As required by Commission rules, UNSE's rate schedules show rates both on a bundled and unbundled basis.

Q. Do you have concerns with the rate design of UNSE's unbundled tariff?

A. Yes. 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. This problem is illustrated for the LPS rate schedule in Figure KCH-1, below.

Figure KCH-1



Q. Please describe Figure KCH-1.

A. Figure KCH-1 compares the unbundled demand *cost* of serving the LPS class with the proposed unbundled demand *charges* for these customers. For LPS customers, the proposed bundled demand charge of $12.48 per kW-month is shown in the bar graph on the right-hand side of Figure KCH-1. This charge is disaggregated into three unbundled components, also illustrated: (1) an unbundled Transmission demand charge of $3.58 per kW-month, (2) an unbundled Local Delivery demand charge of $5.22 per kW-month, and (3) an unbundled Generation Capacity demand charge of $3.68 per kW-month.

The corresponding demand-related *costs* are shown on the left-hand side of the figure. These costs are taken directly from the UNSE cost-of-service study.

Figure KCH-1 shows that the unbundled transmission costs and charges are fully aligned, but the unbundled Local Delivery demand charge and unbundled Generation Capacity demand charge are entirely inconsistent with the results of UNSE's cost-of-service study. That study indicates that generation demand costs for the LPS class to be $9.33 per kW-month and distribution demand costs to be just $0.57 per kW-month.[43] In other words, the cost-of-service study UNSE performed shows that generation demand costs are more than 16 times as great as distribution demand costs for the LPS class, yet UNSE proposes to price generation demand more cheaply than distribution demand! This is a serious problem. A similar problem exists for the MGS and LGS classes.

Q. Why is this a serious problem?

A. It is a serious problem because the fundamental economic proposition in a buy-through rate is that the buy-through customer is able to bypass either all, or a significant portion of, the unbundled generation charges. If the utility's unbundled rate design shifts cost recovery from generation charges to distribution (or delivery) charges, then the avoidable generation costs will be underpriced and unavoidable distribution charges will be overpriced. As a result, the ability of customers to shop for buy-through power will be thwarted. Indeed, that is exactly what is likely to occur if UNSE's unbundled rate design is accepted.

To appreciate this point, we can return to Figure KCH-1. UNSE has in effect re-packaged the aggregate *costs* of G + D shown on the left into the aggregate *charges* of G + D on the right. In so doing, a large portion of the G cost

[43] See UNSE Schedule G-6-1 workpaper. Note that this UNSE workpaper indicates that the bundled demand cost for LPS is $13.47 per kW-month, whereas the bundled demand charge for LPS is proposed to be $12.48/kW-month. The difference between these two amounts is largely recovered in the power factor adjustment charge for this rate schedule.

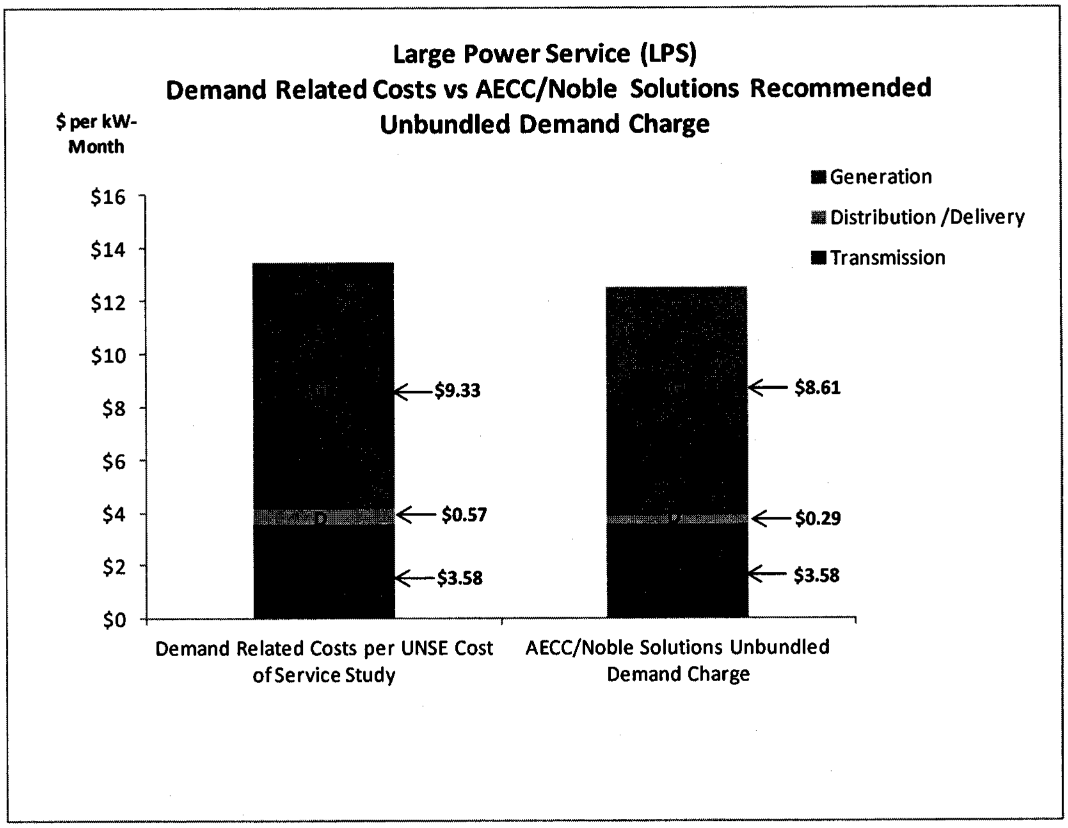
is shifted into the unbundled D charge. This is plainly evident by comparing the two bar graphs. When we consider that the unbundled D charge is *unavoidable* for the buy-through customer, it is obvious that shifting G-related costs into the D charge will hinder the buy-through customer's ability to avoid paying for G-related costs when the buy-through customer contracts for third-party generation service. This situation will significantly and unduly undermine the economics of acquiring generation service in the power market. Indeed, shifting generation-related costs into the distribution (or delivery) charge is contrary to the very purpose of unbundling rates. It also appears to be contrary to the requirements of AAC R14-2-1606.H.2 which states that rates for unbundled services "shall reflect the costs of providing the services."

Q. Have you calculated alternative unbundled rates for the LPS, MGS, and LGS classes?

A. Yes. I have calculated a set of alternative unbundled rates that produce the same bundled demand charge as proposed by UNSE for each of these customer classes, but with unbundled rate components that are aligned with the functional costs identified in UNSE's cost-of-service study. These calculations are presented in Exhibit KCH-1.[44] I have also illustrated the relationship between my proposed unbundled demand charge components for LPS with the underlying cost components in Figure KCH-2, below.

[44] Note that UNSE appears to have inadvertently reversed the Meter Services and Meter Reading unit costs in its workpapers and consequently has accidentally reversed the unbundled charges for these services. I have corrected this error in my proposed unbundled rates in Exhibit KCH-1.

Figure KCH-2



Q. Referring to Figure KCH-2, please explain why your recommended unbundled generation demand charge for LPS is less than the unbundled generation demand cost.

A. As I indicated above, I have designed my recommended unbundled demand charges using the same *bundled* demand charge that UNSE has proposed; given this constraint, my recommended unbundled demand components sum to the $12.48 per kW-month bundled demand charge proposed by UNSE. The difference between the unbundled generation demand cost and my recommended unbundled generation demand charge is recovered in the power factor adjustment charge for this rate schedule proposed by UNSE.

Q. Also referring to Figure KCH-2, please explain why your recommended unbundled delivery service demand charge for LPS is less than the unbundled delivery service demand cost.

A. UNSE's current and proposed rate design recovers a portion of distribution/delivery service costs in a delivery service energy charge. While I generally do not agree with recovering distribution/delivery service costs in an energy charge, I have elected not to challenge this aspect of UNSE's rate design in this case. Therefore, the difference between the distribution/delivery service demand costs and my recommended unbundled distribution/delivery service demand charge is recovered in the delivery service energy charge proposed by UNSE.

Q. What is your recommendation to the Commission on this issue?

A. UNSE's proposed relationship between delivery demand charges and generation capacity demand charges in its unbundled tariff should be rejected. Instead, I recommend that the unbundled rate design presented in Exhibit KCH-1 should be adopted at the UNSE revenue requirement for these classes. If the revenue requirement for these classes is modified, then the underlying relationship among the unbundled components of the demand charges in Exhibit KCH-1 should be retained in any new bundled demand charges.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT KCH-1

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

Line No.	Description	UNSE Unit Cost @ Proposed Rates[1]	UNSE Proposed[2]	AECC/ Noble Solutions Recommended
1	Basic Service Charge Components ($/Cust./Mo.):			
2	Meter Services[3]	$260.68	$101.86	$145.57
3	Meter Reading[3]	$182.42	$145.57	$101.86
4	Billing & Collection	$808.82	$451.63	$451.63
5	Customer Delivery	$896.57	$500.94	$500.94
6	Total	$2,148.50	$1,200.00	$1,200.00
7	Demand Charge Components ($/kW):			
8	Local Delivery	$0.57	$5.22	$0.29
9	Generation Capacity	$9.33	$3.68	$8.61
10	Transmission	$3.58	$3.58	$3.58
11	Total	$13.47	$12.48	$12.48
12	Energy Charge Components ($/kWh):			
13	Local Delivery	NA	$0.00052	$0.00052
14	Power Supply Charges ($/kWh):			
15	Base Power Supply (LPS)	$0.045099	$0.048410	$0.048410
16	Base Power Supply Summer On-Peak - (LPS-TOU)		$0.122510	$0.122510
17	Base Power Supply Summer Off-Peak - (LPS-TOU)		$0.032110	$0.032110
18	Base Power Supply Winter On-Peak - (LPS-TOU)		$0.092110	$0.092110
19	Base Power Supply Winter Off-Peak - (LPS-TOU)		$0.030910	$0.030910
20	PPFAC (%) (see Rider-1 for current rate)	NA	Varies	Varies

Notes:
1. Data Source: UNSE Schedule G-6-1, Sheet 1 of 1.
2. Data Source: UNSE Witness Craig Jones Exhibit CAJ-3, Original Sheet 301-2 & 302-3.
3. UNSE's workpapers appear to reverse the Meter Services and Meter Reading unit costs. AECC/Noble Solutions recommended unbundled charges correct this error.

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

Line No.	Description	UNSE Unit Cost @ Proposed Rates[1]	UNSE Proposed[1]	AECC/ Noble Solutions Recommended
1	Basic Service Charge Components ($/Cust./Mo.):			
2	Meter Services[2]	$32.27	$5.01	$31.32
3	Meter Reading[2]	$5.16	$31.32	$5.01
4	Billing & Collection	$22.82	$22.15	$22.15
5	Customer Delivery	$248.80	$241.52	$241.52
6	Total	$309.05	$300.00	$300.00
7	Demand Charge Components ($/kW):			
8	Demand Delivery	$3.93	$8.29	$0.96
9	Generation Capacity	$6.47	$2.37	$9.70
10	Transmission	$2.30	$2.30	$2.30
11	Total	$12.70	$12.96	$12.96
12	Energy Charge Components ($/kWh):			
13	Local Delivery	NA	$0.00540	$0.00540
14	Power Supply Charges ($/kWh):			
15	Base Power Supply (LGS)	$0.048536	$0.048400	$0.048400
16	Base Power Supply Summer On-Peak - (LGS-TOU)		$0.145510	$0.145510
17	Base Power Supply Summer Off-Peak - (LGS-TOU)		$0.034510	$0.034510
18	Base Power Supply Winter On-Peak - (LGS-TOU)		$0.124510	$0.124510
19	Base Power Supply Winter Off-Peak - (LGS-TOU)		$0.032910	$0.032910
20	Base Power Supply Summer On-Peak - (LGS-TOU-S)		$0.150210	$0.150210
21	Base Power Supply Summer Off-Peak - (LGS-TOU-S)		$0.039210	$0.039210
22	Base Power Supply Winter On-Peak - (LGS-TOU-S)		$0.129210	$0.129210
23	Base Power Supply Winter Off-Peak - (LGS-TOU-S)		$0.037610	$0.037610
24	PPFAC (%) (see Rider-1 for current rate)		Varies	Varies

Notes:
1. Data Source: UNSE Schedule G-6-1, Sheet 1 of 1.
2. Data Source: UNSE Witness Craig Jones Exhibit CAJ-3, Original Sheet 220-2 & 221-2 & 222-2.
3. UNSE's workpapers appear to reverse the Meter Services and Meter Reading unit costs. AECC/Noble Solutions recommended unbundled charges correct this error.

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

Line No.	Description	UNSE Unit Cost @ Proposed Rates[1]	UNSE Proposed[1]	AECC/ Noble Solutions Recommended
1	Basic Service Charge Components ($/Cust./Mo.):			
2	Meter Services[2]	$32.27	$1.67	$10.44
3	Meter Reading[2]	$5.16	$10.44	$1.67
4	Billing & Collection	$22.82	$7.38	$7.38
5	Customer Delivery	$248.80	$80.51	$80.51
6	Total	$309.05	$100.00	$100.00
7	Demand Charge Components ($/kW):			
8	Demand Delivery	$3.93	$8.38	$2.26
9	Generation Capacity	$6.47	$2.37	$8.40
10	Transmission	$2.30	$2.30	$2.30
11	Total	$12.70	$13.05	$12.96
12	Energy Charge Components ($/kWh):			
13	Local Delivery	NA	$0.00550	$0.00550
14	Power Supply Charges ($/kWh):			
15	Base Power Supply (MGS)	$0.048536	$0.048440	$0.048440
16	Base Power Supply Summer On-Peak - (MGS-TOU)		$0.145510	$0.145510
17	Base Power Supply Summer Off-Peak - (MGS-TOU)		$0.034510	$0.034510
18	Base Power Supply Winter On-Peak - (MGS-TOU)		$0.124510	$0.124510
19	Base Power Supply Winter Off-Peak - (MGS-TOU)		$0.032910	$0.032910
20	Base Power Supply Summer On-Peak - (MGS-TOU-S)		$0.150210	$0.150210
21	Base Power Supply Summer Off-Peak - (MGS-TOU-S)		$0.039210	$0.039210
22	Base Power Supply Winter On-Peak - (MGS-TOU-S)		$0.129210	$0.129210
23	Base Power Supply Winter Off-Peak - (MGS-TOU-S)		$0.037610	$0.037610
24	PPFAC (%) (see Rider-1 for current rate)		Varies	Varies

Notes:
1. Data Source: UNSE Schedule G-6-1, Sheet 1 of 1.
2. Data Source: UNSE Witness Craig Jones Exhibit CAJ-3, Original Sheet 210-2 & 211-2 & 212-2.
3. UNSE's workpapers appear to reverse the Meter Services and Meter Reading unit costs. AECC/Noble Solutions recommended unbundled charges correct this error.