SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT BOARD MEETING NOTICE AND AGENDA – AMENDED

SPECIAL BOARD OF DIRECTORS

Thursday, August 10, 2023, 9:30 AM

SRP Administration Building
1500 N. Mill Avenue, Tempe, AZ 85288

Call to Order
Roll Call

1. Proposed SRP Buy-Through Program

   A. Management's Detailed Proposal .... BRIAN KOCH and ADAM PETERSON

   B. Board Consultant's Review of Management's Proposal
   .... BRUCE CHAPMAN, Christensen Associates Energy Consulting

   C. Public Comments .... PRESIDENT DAVID ROUSSEAU

   D. Management Closing Comments and Next Steps
   .... BRIAN KOCH and AIDAN McSHEFFREY

2. Adjourn .... PRESIDENT DAVID ROUSSEAU

The Board may vote during the meeting to go into Executive Session, pursuant to A.R.S. §38-431.03 (A)(3), for the purpose of discussion or consultation for legal advice with legal counsel to the Board on any of the matters listed on the agenda.

The Board may go into Closed Session, pursuant to A.R.S. §30-805(B), for discussion of records and proceedings relating to competitive activity, including trade secrets or privileged or confidential commercial or financial information.

Visitors: The public has the option to attend in-person or observe via Zoom and may receive teleconference information by contacting the Corporate Secretary's Office at (602) 236-4398. If attending in-person, all property in your possession, including purses, briefcases, packages, or containers, will be subject to inspection.

THE NEXT BOARD MEETING IS SCHEDULED FOR MONDAY, SEPTEMBER 11, 2023

SRP Management's Proposed Buy-through Program

Program Summary

In accordance with A.R.S. § 30-810 (effective September 24, 2022), SRP must offer a buy-through program (Program) by January 1, 2024. The Program provides for SRP to purchase electricity at the direction of a retail customer from a third-party generation service provider (GSP). The Program will specify the terms, conditions, and limitations, including a minimum qualifying load and a maximum amount of Program participation. It must be structured to maintain system reliability and to avoid a cost shift to nonparticipating customers.

Activities to Date

SRP internal teams have been at work developing the Program parameters since October 2022. Select activities taken to date include:

Detailed documents have been developed and posted on SRPnet.com for customers and Stakeholders to see. Documents include a Program overview, Program design, Program requirements, the Board's consultant report, and Board and stakeholder presentations (June 5th, June 27th, July 12th, July 18th).

Management's Proposal

Management's proposed Program size is 200 MW demand, minimum customer size of 5 MW, maximum customer participation of 50 MW, with 60% load factor, and applicable to customers served on E-65 and E-67. The Program terms specify the customer, the GSP and SRP's responsibilities to maintain system reliability such as firm capacity, legal and regulatory requirements, reserve margins, ancillary services, and energy imbalance. The Program incorporates a pricing design structure to recover any incremental program cost to avoid any cost shift to non-participating customers. Those costs include incremental or under-recovered administrative, reserve capacity, early technology adoption, energy imbalance and Fuel and Purchase Power Adjustment (FPPAM) costs. Where cost savings occur, those applicable cost savings are applied to the buy-through customer in the form of generation capacity and going forward FPPAM credit.

Next Steps

Next steps include Management presenting in detail its proposed Program followed by the Board Consultant's presentation at the August 10th Special Board Meeting. Final stakeholder comments are due by September 18th. Management will make its final recommendation to the Board in a Special Meeting scheduled for September 26th.

BUY-THROUGH
PROGRAM REQUIREMENTS
[DRAFT PROPOSAL 8/10/23]

This document details the requirements for participation in SRP's Buy-through Program (the "Program"). In the event of any conflict between these Program Requirements and the Buy-Through Program Design document approved by SRP's Board of Directors (the "Program Design Document"), the Program Design Document will control. A current copy of the Program Design Document is attached to these Program Requirements as Appendix A. Capitalized terms used and not defined in these Program Requirements have the meanings given those terms in the Program Design Document. SRP reserves the right to modify these Program Requirements at any time. Any modifications will be posted on SRP's website.

If you have any questions about the Program or these Program Requirements, please contact your Strategic Energy Manager. Contact information is on your SRP bill.

SECTION I: PROGRAM OVERVIEW

1.1. The Program allows a limited number of eligible customers (each, a "Customer") to arrange for a designated third-party Generation Service Provider (GSP), selected by the Customer, to sell and deliver wholesale energy to SRP, for the Customer's benefit and at the Customer's sole expense.

1.2. The energy provided by the GSP is in lieu of SRP's standard generation service.

1.3. Participation in the Program requires the execution of one or more Service Contracts with respect to each participating Account. For purposes of these Program Requirements, an "Account" is the SRP billing account applicable to a specific location for electric delivery via the service entrance station and meters.

1.4. Upon the GSP's delivery of energy to SRP's transmission system, SRP will provide transmission and delivery service to the Customer in accordance with the applicable SRP Standard Electric Price Plan, except as provided in the Program Design Document.

1.5. SRP will pay for and accept delivery of the energy from the GSP, and bill the Customer for the amounts paid by SRP to the GSP.

1.6. The Program's total participation (the sum of the Customer Participating Load for all enrolled Accounts) will be limited to 200 MW.

1.7. A single Customer may not designate more than one GSP, although a GSP may provide energy for multiple Customers.

1.8. SRP may cancel the Customer's participation if the Customer ceases to meet the qualifications and satisfy all conditions and requirements for participation in the Program.

SECTION II: PROGRAM ELIGIBILITY REQUIREMENTS & PARTICIPATION CRITERIA

2.1 The Program is available only to an Account receiving and qualifying for electric service under SRP Standard Electric Price Plans E-65 or E-67 and otherwise meeting the requirements in the "Applicability" section of the Program Design Document.

2.2 SRP will offer an initial Program enrollment period per the timeline provided in Appendix C, after which participation will be on a first come, first served basis.

2.3 During the initial Program enrollment period only, 100 MW will be available to Accounts with Annual Peak Demand exceeding 25 MW, and 100 MW will be available to Accounts with Annual Peak

Demand less than or equal to 25 MW. If either group does not fully subscribe their 100 MW allotment, then the remaining unsubscribed capacity will become available to the other group.

2.4 SRP will review participation annually to evaluate Customer growth and Program available capacity.

2.5 After the initial Program enrollment period, interested customers may request to participate by notifying their Strategic Energy Manager. If participation is available to that customer, then within 5 business days of receiving the customer's request, SRP will provide an invitation to participate, which will include the prospective Customer Participating Load and one or more options for Delivery Points (as defined in Section VII below). If the customer fails to execute the required Service Contracts within 90 days of receipt of SRP's invitation, the invitation will lapse and the customer must submit a new participation request. SRP will process requests on a first come, first served basis.

2.6 SRP will add interested customers to a wait list if inquiring after the Program is fully subscribed.

SECTION III: CUSTOMER PARTICIPATION

3.1 Subject to the 50 MW per-Customer and per-Account cap and available capacity in the Program, each Account must participate with its full load, except to the extent the Account participates in another SRP program or offering, participation in which is determined by SRP to be incompatible with Program participation (a "Concurrent Program").

3.2 SRP will determine the initial Customer Participating Load and Customer Participation Factor at the time of Account enrollment. SRP may thereafter adjust the Customer Participating Load and Customer Participation Factor as set forth in Appendix B.

3.3 The Customer must sign separate Service Contracts for each Account.

3.4 The Customer must select the GSP and arrange for the GSP's execution of the Service Contracts under which the GSP will deliver energy to SRP (the "GSP Contracts").

3.5 The Customer and the GSP must execute the GSP Contracts at least 30 days prior to the flow of energy from the GSP.

3.6 The Customer must continually maintain the GSP Contracts, subject to a 60-day grace period.

3.7 The Customer may cancel its participation in the Program at any time, with cancellation generally effective 36 months after delivery of the cancellation notice, as provided in the Program Design Document.

3.8 If the Customer's Program participation is cancelled, the Customer will be ineligible for Program participation for one year from the effective date of cancellation.

SECTION IV: GENERATION SERVICE PROVIDER

4.1 The GSP must meet all legal, regulatory, and SRP credit requirements to sell and deliver wholesale energy to SRP.

4.2 The GSP must be a member of WSPP and provide firm capacity/energy sale or exchange service under WSPP Service Schedule C.

4.3 The GSP must bill SRP on a monthly basis and separately for each Account, for the energy delivered to SRP.

4.4 Each GSP Contract must have a term of at least one year.

4.5 The GSP must comply with all SRP requirements for the secure transfer of Customer billing information and other sensitive information.

SECTION V: RESUPPLY

5.1 If SRP cancels the Customer's Program participation, then unless a shorter period is provided in accordance with the Program Design Document, SRP will supply Resupply Energy for the period between the effective date of cancellation and the date that is 36 months after notice of cancellation is delivered.

5.2 SRP will provide Resupply Energy during any period in which there are no GSP Contracts in effect for the Account.

5.3 SRP will charge the Customer for Resupply Energy at the price set forth in the Program Design Document.

5.4 SRP will provide Resupply Energy in whole day increments following the WECC prescheduled flow dates.

SECTION VI: IMBALANCE

6.1 SRP will calculate Energy Imbalance each month based on preliminary values, with reconciliation for actual figures to follow in subsequent months.

6.2 Any Energy Imbalance, regardless of cause, will be settled at the applicable price provided in the Program Design Document.

6.3 The Customer must pay for settlement of imbalance charges by the bill's due date.

6.4 As detailed in the Program Design Document, the Customer's Program participation is subject to cancellation by SRP for repeated imbalances.

SECTION VII: ENERGY SCHEDULING AND DELIVERY

7.1 The GSP must provide firm energy to serve 100% of the Account's Total Load Requirements.

7.2 The Customer is responsible for providing the GSP with accurate hourly load forecasts of the Account's Total Load Requirements. The forecast of the Account's Total Load Requirements can generally be determined by multiplying the hourly forecast of total load on the Account by the Customer Participation Factor, then increasing that amount by 3.43% to reflect line losses between the Delivery Point (defined below) and the service entrance station for the Account. SRP will have no obligation to calculate or verify the Customer's forecast.

7.3 The GSP must deliver energy to a 230 kV Receiving Station approved by SRP (the "Delivery Point").

7.4 The GSP is responsible for procuring or providing firm transmission service to the SRP Delivery Point.

7.5 Energy deliveries from the GSP must commence on the first day of a billing cycle.

7.6 SRP schedulers will appropriately tag energy in accordance with the WECC Preschedule Calendar.

7.7 The GSP must register an STD SS (Standard Self-Schedule) T Wheel with CAISO for energy wheeled through CAISO.

7.8 The GSP must designate the applicable resource as "High Priority Export" with CAISO, if the energy is sourced from CAISO.

7.9 On a monthly basis, the GSP must submit to the SRP Day Ahead trading desk a monthly forecast of the schedule of hourly loads for each day of the month, even if the hourly load is for 0 MW. The GSP must deliver the monthly forecast, in the format required by SRP, via email by 5:00 a.m. at least seven (7) business days prior to the first preschedule day of the month (as determined by the WECC Preschedule Calendar guidelines). The hourly loads must be stated in whole MW.

7.10 SRP will enter the provided hourly load forecasts in the trade capture system.

7.11 The GSP must report any daily changes to the schedule to the SRP Day Ahead trading desk in the required Excel format via email by 5:00 a.m. on the last trade day before the scheduled energy flow day (as determined by the WECC Preschedule Calendar guidelines).

7.12 On a daily basis, SRP will designate the daily volumes per Designating Network Resources posted on the OASIS website.

7.13 The GSP must provide physical path information to SRP by 11:00 a.m. on the last preschedule day before the scheduled energy flow day (as determined by the WECC Preschedule Calendar guidelines), via Instant Message per industry standard. The physical path information must include all upstream information relative to the agreed upon Delivery Point.

7.14 The GSP may provide revised physical path information for a particular hour to SRP Real-Time Trading in an emergency situation where the initial firm generation source or transmission path is cut or interrupted, conditioned on providing notice at least ninety (90) minutes prior to the beginning of the operating hour. For example, a revision for hour-ending 4:00 p.m. must be provided to SRP by 1:00 p.m.

7.15 SRP may cut the GSP's schedule when deemed necessary by SRP due to an SRP system requirement or emergency, in which event SRP will not charge for any resulting Energy Imbalance.

7.16 The GSP must call SRP Real-Time Trading to notify SRP of any outage or failure as soon as practicable.

SECTION VIII: BILLING

8.1 All Program charges and credits that will appear on the Customer's bill are set forth in the Program Design Document.

8.2 The components of the monthly Buy-Through Charge may be bundled together, or may appear as two or more separate line items on the Customer's bill.

8.3 SRP will issue the Customer's bill on the 2nd business day of the month, but bills may be subject to subsequent reconciliation based on the actual amount billed by the GSP.

8.4 The GSP must validate the tagged hourly MW provided by SRP and send it back to SRP with any agreed upon modifications, with receipt by SRP no later than the tenth (10th) calendar day of each month.

APPENDIX A: Buy-Through Program Design Document

[SEE ATTACHED]

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT

BUY-THROUGH PROGRAM

Effective: January 1, 2024

AVAILABILITY:

Availability of SRP's Buy-through Program (the "Program") is subject to equipment availability and other conditions, as determined in SRP's sole discretion. Total Customer Participating Load among all participating customers (each, a "Customer") will be limited to 200 Megawatts (MW).

APPLICABILITY:

The Program is established to permit a Customer to direct SRP's purchase of energy for the Customer's benefit and at the Customer's sole expense. The Program is open to an individual Customer account receiving and qualifying for electric service under SRP Standard Electric Price Plans E-65 or E-67 and having, in the 12-month period immediately preceding the Customer's enrollment in the Program, a minimum Annual Peak Demand of 5 MW and a minimum average monthly Load Factor (as defined in SRP's Rules and Regulations) of 60%.

DEFINITIONS:

<u>Annual Peak Demand</u>: The maximum thirty-minute integrated kW demand for the Customer account, as measured by the meter, over a 12-month period. This amount will be based on the 12-month period immediately preceding the Customer's initial enrollment in the Program, unless recalculated as set forth in the Program Requirements.

<u>Customer Participating Billing Demand</u>: The maximum thirty-minute integrated kW demand occurring during the on-peak period of the applicable billing cycle, as measured by the meter, multiplied by the Customer Participation Factor.

<u>Customer Participating Load</u>: The participating demand (in MW) for the Customer account served under the Program. This amount is determined at the time of the Customer's initial enrollment in the Program, but is subject to change as set forth in the Program Requirements.

<u>Customer Participating Metered Energy</u>: The hourly metered energy for the Customer account multiplied by the Customer Participation Factor.

<u>Customer Participation Factor</u>: The ratio of Customer Participating Load to Annual Peak Demand, expressed as a percentage.

<u>Energy Imbalance</u>: For each hour, the difference between the hourly delivered energy from the GSP (reduced to reflect line losses of 3.32%) and the actual Customer Participating Metered Energy.

Generation Service Provider (GSP): A third-party provider of wholesale energy that (a) meets SRP's creditworthiness and other counterparty standards and meets all requirements and conditions set forth in the Program Requirements for the sale of energy to SRP under the Program, (b) is selected by the Customer to provide wholesale energy to SRP for the Customer's benefit, and (c) enters into the Service Contract(s).

Program Requirements: The detailed terms and conditions established by SRP for enrollment and participation in the Program, as may be modified from time to time by SRP management, which shall be published on SRP's website (www.SRPnet.com).

Resupply Energy: Energy provided by SRP to the Customer to replace energy that would have been provided by the GSP but for the cancellation of the Customer's Program participation, or the failure to have a Service Contract in effect with a GSP.

Resupply Price: The hourly price of energy under the Palo Verde Peak or Off-peak Intercontinental Exchange Day Ahead index (or another comparable index selected by SRP if the foregoing index is unavailable), plus the greater of $10 per MWh (prorated for any partial MWh) or 10% of the index price.

Service Contracts: The written contracts, on SRP's standard form, among SRP, the Customer, and the GSP, as applicable, setting forth the terms and conditions of the Customer's participation in the Program and the GSP's delivery of energy.

Total Load Requirements: The Customer Participating Metered Energy, increased to reflect line losses of 3.32% from the point of delivery on SRP's transmission system to the Customer's site.

CONDITIONS:

In addition to all conditions of the Program Requirements, the Customer's participation in the Program is subject to the following:

A. SRP, in its sole discretion, may require the Customer to have interval metering and other metering equipment approved by SRP. If the Customer does not have such metering, SRP will install the metering equipment at the Customer's expense. The Customer will be responsible for providing and maintaining any communication facilities and equipment associated with the meter(s), such as a phone line.

B. Neither the Customer Participating Load for a single account, nor the total Customer Participating Loads for all accounts of a single Customer, may exceed 50 MW.

C. Except as otherwise provided in the Program Requirements, and subject to the 50 MW cap, the Customer Participating Load must equal 100% of the Annual Peak Demand, less any portion thereof that SRP determines, in its sole discretion, will be excluded due to the Customer's participation in another SRP program or offering.

D. SRP will provide transmission, delivery, and network services to the Customer according to SRP's standard terms and conditions for retail electric service, except as provided herein.

E. The Customer must be in good standing with SRP (meaning that all arrears have been brought current or arrangements suitable to SRP have been made and necessary deposits have been posted) to enroll in the Program.

F. The Customer's participation in the Program will continue until the date on which such participation is cancelled under the sections below titled "Imbalance Service" or "Cancellation," or, if sooner, on the date on which the Program is terminated.

G. The Customer may cancel service under this Program at any time by delivering notice to SRP, subject to the section below titled "Cancellation."

H. If SRP or the Customer cancels the Customer's participation in the Program, the Customer will not be allowed to participate in the Program again until one year after the effective date of cancellation.

I. Participation in the Program requires execution of one or more Service Contracts satisfying all requirements herein and in the Program Requirements.

J. The pricing and other terms and conditions of the Program set forth herein are subject to change at any time, with the approval of SRP's Board of Directors.

SERVICE CONTRACTS:

The Service Contracts will include, without limitation, the following terms and conditions:

A. The GSP must deliver sufficient firm energy, to the point of delivery agreed to by SRP, to meet the Customer's Total Load Requirements, on an hourly basis, for a period of at least one year. The GSP is responsible for procuring or providing transmission service to deliver the energy to SRP's delivery point.

B. Unless SRP directs the Customer to pay GSP invoices directly, SRP will pay the GSP for the energy delivered; SRP will bill the Customer for all amounts paid by SRP to the GSP.

C. SRP shall have no liability for any losses, claims, or damages arising from a default by the GSP or the Customer.

D. SRP will settle with the Customer for Energy Imbalance and other relevant costs monthly as specified in the “Customer Charges and Credits” section below.

E. The GSP must provide a separate monthly invoice for the energy delivered to SRP for the benefit of the Customer.

F. SRP will serve as the scheduling coordinator. The GSP must provide SRP with monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule in accordance with the Program Requirements.

G. SRP will apply all payments received from the Customer to services rendered by SRP before remitting any amounts to the GSP. The Customer will be solely responsible for any shortfall.

IMBALANCE SERVICE:

SRP will calculate Energy Imbalance for the Customer account.

A. Energy Imbalance will be settled as follows on an hourly basis:

   i. If Energy Imbalance is less than or equal to the greater of +/- 15% or 2MW (a “Tier 1 Energy Imbalance”), it will be settled at the applicable CAISO External Load Aggregation Point (ELAP) price.

   ii. If Energy Imbalance exceeds the greater of +/- 15% or 2MW (a “Tier 2 Energy Imbalance”), then (i), if due to the hourly delivered energy from the GSP exceeding the hourly Customer Participating Metered Energy, it will be settled at 75% of the applicable ELAP price when the ELAP price is positive, or 125% of the ELAP price if negative, or (ii), if due to the hourly Customer Participating Metered Energy exceeding the hourly delivered energy from the GSP, it will be settled at 125% of the applicable ELAP price when the ELAP price is positive, or 75% of the ELAP price if negative.

B. If a Tier 2 Energy Imbalance occurs on more than 20% of the hours in a calendar month, there will be deemed to have occurred an “Excessive Imbalance.” SRP will provide written notice to the GSP and the Customer of any Excessive Imbalance. If an Excessive Imbalance occurs two or more times within any rolling 12-month period, SRP may, in its discretion, terminate the Service Contract with respect to the GSP and cancel the Customer’s participation in the Program, by providing advance written notice as set forth in the Service Contracts. Cancellation due to an Excessive Imbalance may result in SRP declaring the GSP ineligible for the sale of energy to SRP under the Program.

REPLACEMENT OF GSP:

If the Service Contracts with respect to the GSP expire or are terminated, then until energy deliveries commence under Service Contracts with a replacement GSP, or the date on which cancellation of the Customer's participation in the Program is effective, SRP will provide Resupply Energy at the Resupply Price. If there is no effective Service Contract with a GSP for a period of 60 consecutive days, SRP may cancel the Customer's participation in the Program.

CANCELLATION:

A. If the Customer ceases to meet the qualifications, and satisfy all conditions and requirements, for participation in the Program, or fails to comply with the Service Contracts, SRP may cancel the Customer's participation in the Program by providing advance written notice as set forth in the Service Contracts.

B. If the Customer delivers notice to SRP cancelling its participation in the Program, then the cancellation will take effect 36 months after Customer's delivery of the notice of cancellation, or, if requested by the Customer, a sooner date agreed to by SRP if and when SRP determines, in its sole discretion, that allowing an earlier effective date would not adversely impact the costs or reliability of service to SRP's other customers. Any cancellation is conditioned upon the concurrent termination of the Service Contracts.

C. If SRP cancels the Customer's participation in the Program for any reason, then SRP will provide Resupply Energy at the Resupply Price, and all Program charges and payments will continue to apply, for the period of time between the effective date of cancellation and the date that is 36 months after notice of cancellation is delivered, or a shorter period specified by SRP if and when SRP determines, in its sole discretion, that reducing that period would not adversely impact the costs or reliability of service to SRP's other customers.

D. Any waivers or reductions of the 36-month periods referenced in subsections B and C above will be granted, if at all, in the order in which the Cancellation Notices are received or delivered, as applicable, by SRP.

CUSTOMER CHARGES AND CREDITS:

A. Customer's participation in the Program does not replace or reduce the charges incurred by the Customer under the Price Plan under which the Customer takes service, except as follows:

    i. The Fuel and Purchased Power Adjustment Mechanism (FPPAM) component will not apply to the Customer Participating Metered Energy, subject to Paragraph E below; and

ii. The Generation (kW and Energy) component will not apply to the Customer Participating Metered Energy or Customer Participating Billing Demand.

B. The Customer will be assessed a monthly Buy-Through Charge of $4.15/kW of Customer Participating Billing Demand, to recover costs and charges incurred by SRP to maintain capacity reserves, administer the Program, and recover the Customer's share of Early Technology Adoption costs (costs related to certain existing renewable generating facilities on SRP's system).

C. SRP will charge the Customer for all amounts paid by SRP to the GSP.

D. SRP will charge or credit the Customer for the amounts associated with any Energy Imbalance, as calculated under the "Imbalance Service" section.

E. If, at the time of the Customer's enrollment in the Program, the FPPAM over- or under-collection balance exceeds $20 Million, the Customer will be assessed an FPPAM Settlement Adjustment (FSA) based on the Customer's pro-rata share of the FPPAM over- or under-collection balance.

i. The FSA will be calculated as follows:

FSA = F x (C / T)

Where:

F = FPPAM over- or under-collection balance in excess of $20 Million

C = Customer's energy usage during the period in which the FPPAM over- or under-collection balance accumulated

T = Total energy served by SRP during the period in which the FPPAM over- or under-collection balance accumulated

ii. The Customer will have the option to settle the FSA as a lump-sum credit or payment (as applicable), or in 36 equal monthly credits or payments.

iii. As of the date on which cancellation of the Customer's Program participation is effective, SRP will reconcile the difference between the FSA and the amount that the Customer has already paid or has been credited. For purposes of that reconciliation, the Customer's pro-rata share of the FPPAM over- or under-collection balance (calculated as “C / T” in the formula above) will be the same percentage that was calculated at the time of the Customer’s enrollment in the Program.

F. Any taxes or governmental impositions which are or may in the future be assessed based on gross revenues of SRP 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 will be applied to the Customer’s bill.

APPENDIX B: Customer Participating Load and Customer Participation Factor

Methodology: During the initial Program enrollment period, SRP will determine for each Account the initial Customer Participating Load and Customer Participation Factor, as follows:

Step 1: SRP will determine the Account's Annual Peak Demand in the 12-month period immediately preceding the enrollment date (the "Baseline Peak Demand").

Step 2: SRP will make a preliminary calculation of the Account's Customer Participating Load, which will equal the lesser of (a) 100% of the Baseline Peak Demand, less the maximum demand participating in a Concurrent Program, or (b) 50 MW (the "Preliminary Participating Load").

Step 3: If the Preliminary Participating Loads for all Accounts total more than 200 MW (an "Oversubscription"), then SRP will determine each Account's Customer Participating Load using a pro-rata methodology based on the Baseline Peak Demand of each Account, per the timeline provided in Appendix C. Otherwise, the Customer Participating Load will equal the Preliminary Participating Load.

Step 4: SRP will calculate the Customer Participation Factor by dividing the Customer Participating Load by the Baseline Peak Demand.

After the initial Program enrollment period, SRP will process Program participation applications on a first come, first served basis. For Accounts enrolling after the initial enrollment period, the Customer Participating Load will be the lesser of the Preliminary Participating Load or available Program capacity.

SRP may review and re-calculate the Account's Annual Peak Demand on an annual basis. If the Annual Peak Demand for any year differs by more than 15% from the Annual Peak Demand figure used to calculate the then-current Customer Participation Factor, SRP may adjust the Customer Participating Load and Customer Participation Factor based on the updated Annual Peak Demand.

Examples: The following examples are intended for illustrative purposes only to demonstrate the calculation of the Customer Participating Load and Customer Participation Factor during the initial Program enrollment period.

- If there is no Oversubscription, the Account is not participating in a Concurrent Program, and Baseline Peak Demand is 45 MW, then the Customer Participating Load will be 45 MW, and the Participation Factor will be 100%.

- If there is no Oversubscription, the Account is not participating in a Concurrent Program, and Baseline Peak Demand is 55 MW, then the Customer Participating Load will equal 50 MW, and the Customer Participation Factor will be 91%.

- If there is no Oversubscription, the Baseline Peak Demand is 50 MW, and the Account is allocated 20% of the generation from a 100 MW solar facility under a Concurrent Program, then the Customer Participating Load will be 30 MW (50 minus 20), and the Customer Participation Factor will be 60% (30 divided by 50). However, if, under this example, the Baseline Peak Demand were 100 MW, then the Customer Participating Load will be 50 MW instead of 80 MW, due to the 50 MW cap.

APPENDIX C: initial Enrollment period

- 10/2/23 – 10/27/23: Customers must submit applications for eligible accounts
- 10/30/23 – 11/17/23: SRP will calculate and notify customers of their Customer Participating Load
- 12/1/23: Deadline for execution of GSP Contracts for SRP to begin receiving energy on 1/1/24. If the GSP Contracts are executed after this date, energy deliveries will commence as of the first day of the billing cycle that starts on or immediately after the 30th date after execution of the GSP Contracts.

BUY-THROUGH
PROGRAM REQUIREMENTS
[DRAFT PROPOSAL ~~6/13/23~~8/10/23]

This document details the requirements for participation in SRP's Buy-through Program (the "Program"). In the event of any conflict between these Program Requirements and the Buy-Through Program Design document approved by SRP's Board of Directors (the "Program Design Document"), the Program Design Document will control. A current copy of the Program Design Document is attached to these Program Requirements as Appendix A. Capitalized terms used and not defined in these Program Requirements have the meanings given those terms in the Program Design Document. SRP reserves the right to modify these Program Requirements at any time. Any modifications will be posted on SRP's website.

If you have any questions about the Program or these Program Requirements, please contact your Strategic Energy Manager. Contact information is on your SRP bill.

SECTION I: PROGRAM OVERVIEW

1.1. The Program allows a limited number of eligible customers (each, a "Customer") to arrange for a designated third-party Generation Service Provider (GSP), selected by the Customer, to sell and deliver wholesale energy to SRP, for the Customer's benefit and at the Customer's sole expense.

1.2. The energy provided by the GSP is in lieu of SRP's standard generation service.

1.3. Participation in the Program requires the execution of one or more Service Contracts with respect to each participating Account. For purposes of these Program Requirements, an "Account" is the SRP billing account applicable to a specific location for electric delivery via the service entrance station and meters.

1.4. Upon the GSP's delivery of energy to SRP's transmission system, SRP will provide transmission and delivery service to the Customer in accordance with the applicable SRP Standard Electric Price Plan, except as provided in the Program Design Document.

1.5. SRP will pay for and accept delivery of the energy from the GSP, and bill the Customer for the amounts paid by SRP to the GSP.

1.6. The Program's total participation (the sum of the Customer Participating Load for all enrolled Accounts) will be limited to 200 MW.

1.7. A single Customer may not designate more than one GSP, although a GSP may provide energy for multiple Customers.

1.8. SRP may cancel the Customer's participation if the Customer ceases to meet the qualifications and satisfy all conditions and requirements for participation in the Program.

SECTION II: PROGRAM ELIGIBILITY REQUIREMENTS & PARTICIPATION CRITERIA

2.1 The Program is available only to an Account receiving and qualifying for electric service under SRP Standard Electric Price Plans E-65 or E-67 and otherwise meeting the requirements in the “Applicability” section of the Program Design Document.

2.2 SRP will offer an initial Program enrollment period ~~prior to January 1, 2024~~per the timeline provided in Appendix C, after which participation will be on a first come, first served basis.

2.3 During the initial Program enrollment period only, 100 MW will be available to Accounts with Annual Peak Demand exceeding 25 MW, and 100 MW will be available to Accounts with Annual Peak Demand less than or equal to 25 MW. If either group does not fully subscribe their 100 MW allotment, then the remaining unsubscribed capacity will become available to the other group.

2.4 SRP will review participation annually to evaluate Customer growth and Program available capacity.

2.5 After the initial Program enrollment period, interested customers may request to participate by notifying their Strategic Energy Manager. If participation is available to that customer, then within 5 business days of receiving the customer’s request, SRP will provide an invitation to participate, which will include the prospective Customer Participating Load and one or more options for Delivery Points (as defined in Section VII below). If the customer fails to execute the required Service Contracts within 90 days of receipt of SRP’s invitation, the invitation will lapse and the customer must submit a new participation request. SRP will process requests on a first come, first served basis.

2.6 ~~2.5~~ SRP will add interested customers to a wait list if inquiring after the Program is fully subscribed.

SECTION III: CUSTOMER PARTICIPATION

3.1 Subject to the 50 MW per -Customer and per-Account cap and available capacity in the Program, each Account must participate with its full load, except to the extent the Account participates in another SRP program or offering, participation in which is determined by SRP to be incompatible with Program participation (a “Concurrent Program”).

3.2 SRP will determine the initial Customer Participating Load and Customer Participation Factor at the time of Account enrollment. SRP may thereafter adjust the Customer Participating Load and Customer Participation Factor as set forth in Appendix B.

3.3 The Customer must sign separate Service ~~Contract(s)~~Contracts for each Account.

3.4 The Customer must select the GSP and arrange for the GSP’s execution of the Service ~~Contract(s)~~Contracts under which the GSP will deliver energy to SRP (the “GSP Contracts”).

3.5 The Customer and the GSP must execute the GSP Contracts at least 30 days prior to the flow of energy from the GSP.

3.6 The Customer must continually maintain the GSP Contracts, subject to a 60-day grace period.

3.7 The Customer may cancel its participation in the Program ~~upon~~ at ~~least three years’ advance notice to SRP~~any time, with cancellation generally effective 36 months after delivery of the cancellation notice, as provided in the Program Design Document.

3.8 If the Customer’s Program participation is cancelled, the Customer will be ineligible for Program participation for one year from the effective date of cancellation.

SECTION IV: GENERATION SERVICE PROVIDER

4.1 The GSP must meet all legal, regulatory, and SRP credit requirements to sell and deliver wholesale energy to SRP.

4.2 The GSP must be a member of WSPP and provide firm capacity/energy sale or exchange service under WSPP Service Schedule C.
4.3 The GSP must bill SRP on a monthly basis and separately for each Account, for the energy delivered to SRP.
4.4 Each GSP Contract must have a term of at least one year.
4.5 The GSP must comply with all SRP requirements for the secure transfer of Customer billing information and other sensitive information.

SECTION V: RESUPPLY

5.1 If SRP ~~will supply Resupply Energy if~~cancels the Customer's Program participation ~~is cancelled with less than three years' notice, and~~, then unless a shorter period is provided in accordance with the Program Design Document, SRP will supply Resupply Energy for the period between the effective date of cancellation and the date that is 36 months after notice of cancellation is delivered.
5.2 SRP will provide Resupply Energy during any period in which there are no GSP Contracts in effect for the Account.
5.3 ~~5.2~~ SRP will charge the Customer for Resupply Energy at the price set forth in the Program Design Document.
5.4 ~~5.3~~ SRP will provide Resupply Energy in whole day increments following the WECC prescheduled flow dates.

SECTION VI: IMBALANCE

6.1 SRP will calculate Energy Imbalance each month based on preliminary values, with reconciliation for actual figures to follow in subsequent months.
6.2 Any Energy Imbalance, regardless of cause, will be settled at the applicable price provided in the Program Design Document.
6.3 The Customer must pay for settlement of imbalance charges by the bill's due date.
6.4 As detailed in the Program Design Document, the Customer's Program participation is subject to cancellation by SRP for repeated imbalances.

SECTION VII: ENERGY SCHEDULING AND DELIVERY

7.1 The GSP must provide firm energy to serve 100% of the Account's Total Load Requirements.
7.2 The Customer is responsible for providing the GSP with accurate hourly load forecasts of the Account's Total Load Requirements. The forecast of the Account's Total Load Requirements can generally be determined by multiplying the hourly forecast of total load on the Account by the Customer Participation Factor, then increasing that amount by ~~4.32~~3.43% to reflect line losses between the Delivery Point (defined below) and the service entrance station for the Account. SRP will have no obligation to calculate or verify the Customer's forecast.
7.3 The GSP must deliver energy to a 230 kV Receiving Station approved by SRP (the "Delivery Point").
7.4 The GSP is responsible for procuring or providing firm transmission service to the SRP Delivery Point.
7.5 Energy deliveries from the GSP must commence on the first day of a billing cycle.
7.6 SRP schedulers will appropriately tag energy in accordance with the WECC Preschedule Calendar.
7.7 The GSP must register an STD SS (Standard Self-Schedule) T Wheel with CAISO for energy wheeled through CAISO.

7.8 The GSP must designate the applicable resource as "High Priority Export" with CAISO, if the energy is sourced from CAISO.

7.9 On a monthly basis, the GSP must submit to the SRP Day Ahead trading desk a monthly forecast of the schedule of hourly loads for each day of the month, even if the hourly load is for 0 MW. The GSP must deliver the monthly forecast, in the format required by SRP, via email by 5:00 a.m. at least seven (7) business days prior to the first preschedule day of the month (as determined by the WECC Preschedule Calendar guidelines). The hourly loads must be stated in whole MW.

7.10 SRP will enter the provided hourly load forecasts in the trade capture system.

7.11 The GSP must report any daily changes to the schedule to the SRP Day Ahead trading desk in the required Excel format via email by 5:00 a.m. on the last trade day before the scheduled energy flow day (as determined by the WECC Preschedule Calendar guidelines).

7.12 On a daily basis, SRP will designate the daily volumes per Designating Network Resources posted on the OASIS website.

7.13 The GSP must provide physical path information to SRP by 11:00 a.m. on the last preschedule day before the scheduled energy flow day (as determined by the WECC Preschedule Calendar guidelines), via Instant Message per industry standard. The physical path information must include all upstream information relative to the agreed upon Delivery Point.

7.14 The GSP may provide revised physical path information for a particular hour to SRP Real-Time Trading in an emergency situation where the initial firm generation source or transmission path is cut or interrupted, conditioned on providing notice at least ninety (90) minutes prior to the beginning of the operating hour. For example, a revision for hour-ending 4:00 p.m. must be provided to SRP by 1:00 p.m.

7.15 SRP may cut the GSP's schedule when deemed necessary by SRP due to an SRP system requirement or emergency, in which event SRP will not charge for any resulting Energy Imbalance.

7.16 The GSP must call SRP Real-Time Trading to notify SRP of any outage or failure as soon as practicable.

SECTION VIII: BILLING

8.1 All Program charges and credits that will appear on the Customer's bill are set forth in the Program Design Document.

8.2 The components of the monthly Buy-Through Charge may be bundled together, or may appear as two or more separate line items on the Customer's bill.

8.3 SRP will issue the Customer's bill on the 2nd business day of the month, but bills may be subject to subsequent reconciliation based on the actual amount billed by the GSP.

8.4 The GSP must validate the tagged hourly MW provided by SRP and send it back to SRP with any agreed upon modifications, with receipt by SRP no later than the tenth (10th) calendar day of each month.

APPENDIX A: ~~BUY-THROUGH PROGRAM DESIGN DOCUMENT~~Buy-Through Program Design Document

[SEE ATTACHED]

SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT

BUY-THROUGH PROGRAM

Effective: January 1, 2024

AVAILABILITY:

Availability of SRP's Buy-through Program (the "Program") is subject to equipment availability and other conditions, as determined in SRP's sole discretion. Total ~~Program participation~~Customer Participating Load among all participating customers (each, a "Customer") will be limited to 200 Megawatts (MW)~~ of demand~~.

APPLICABILITY:

The Program is established to permit a Customer to direct SRP's purchase of energy for the Customer's benefit and at the Customer's sole expense. The Program is open to an individual Customer account receiving and qualifying for electric service under SRP Standard Electric Price Plans E-65 or E-67 and having, in the 12-month period immediately preceding the Customer's enrollment in the Program, a minimum Annual Peak Demand of 5 MW and a minimum average monthly Load Factor (as defined in SRP's Rules and Regulations) of 60%.

DEFINITIONS:

Annual Peak Demand: The maximum thirty-minute integrated kW demand for the Customer account, as measured by the meter, over a 12-month period. This amount will be based on the 12-month period immediately preceding the Customer's initial enrollment in the Program, unless recalculated as set forth in the Program Requirements.

Customer Participating Billing Demand: The maximum thirty-minute integrated kW demand occurring during the on-peak period of the applicable billing cycle, as measured by the meter, multiplied by the Customer Participation Factor.

Customer Participating Load: The participating demand (in MW) for the Customer account served under the Program~~, not to exceed 50 MW~~. This amount is determined at the time of the Customer's initial enrollment in the Program, but is subject to change as set forth in the Program Requirements.

Customer Participating Metered Energy: The hourly metered energy for the Customer account multiplied by the Customer Participation Factor.

Customer Participation Factor: The ratio of Customer Participating Load to Annual Peak Demand, expressed as a percentage.

Energy Imbalance: For each hour, the difference between the hourly delivered energy from the GSP~~,~~ (reduced to reflect ~~4.14%~~ line losses~~,~~ of 3.32%) and the actual Customer Participating Metered Energy.

Generation Service Provider (GSP): A third-party provider of wholesale energy that (a) meets SRP's creditworthiness and other counterparty standards and meets all requirements and conditions set forth in the Program Requirements for the sale of energy to SRP under the Program, (b) is selected by the Customer to provide wholesale energy to SRP for the Customer's benefit, and (c) enters into the Service Contract(s).

Program Requirements: The detailed terms and conditions established by SRP for enrollment and participation in the Program, as may be modified from time to time by SRP management, which shall be published on SRP's website (www.SRPnet.com).

Resupply Energy: Energy provided by SRP to the Customer ~~due~~ to ~~an Early Termination (as that term is defined below), or during any period in which there is no~~replace energy that would have been provided by the GSP but for the cancellation of the Customer's Program participation, or the failure to have a Service Contract in effect with a GSP.

Resupply Price: The hourly price of energy under the Palo Verde Peak or Off-peak Intercontinental Exchange Day Ahead index (or another comparable index selected by SRP if the foregoing index is unavailable), plus the greater of $10 per MWh (prorated for any partial MWh) or 10% of the index price.

Service Contracts: The written contracts, on SRP's standard form, among SRP, the Customer, and the GSP, as applicable, setting forth the terms and conditions of the Customer's participation in the Program and the GSP's delivery of energy.

Total Load Requirements: The Customer Participating Metered Energy, increased to reflect line losses ~~(scheduled or financially settled)~~ of ~~4.14~~3.32% from the point of delivery on SRP's transmission system to the Customer's site.

CONDITIONS:

In addition to all conditions of the Program Requirements, the Customer's participation in the Program is subject to the following:

A. SRP, in its sole discretion, may require the Customer to have interval metering and other metering equipment approved by SRP. If the Customer does not have such metering, SRP will install the metering equipment at the Customer's expense. The Customer will be responsible for providing and maintaining any communication facilities and equipment associated with the meter(s), such as a phone line.

B. Neither the Customer Participating Load for a single account, nor the total Customer Participating Loads for all accounts of a single Customer, may exceed 50 MW.

C. ~~B.~~ Except as otherwise provided in the Program Requirements, and subject to the 50 MW cap, the Customer Participating Load must equal 100% of the Annual Peak Demand, less any portion thereof that SRP determines, in its sole discretion, will be excluded due to the Customer's participation in another SRP program or offering.

D. ~~C.~~ SRP will provide transmission, delivery, and network services to the Customer according to SRP's standard terms and conditions for retail electric service, except as provided herein.

E. ~~D.~~ The Customer must be in good standing with SRP (meaning that all arrears have been brought current or arrangements suitable to SRP have been made and necessary deposits have been posted) to enroll in the Program.

F. ~~E.~~ The Customer's participation in the Program will continue until the date on which such participation is cancelled under the sections below titled "Imbalance Service" or "Cancellation," or, if sooner, on the date on which the Program is terminated.

G. ~~F.~~ The Customer may cancel service under this Program at any time by delivering notice to SRP, subject to the section below titled "Cancellation."

H. ~~G.~~ If SRP or the Customer cancels the Customer's participation in the Program, the Customer will not be allowed to participate in the Program again until one year after the effective date of cancellation.

I. ~~H.~~ Participation in the Program requires execution of one or more Service Contracts satisfying all requirements herein and in the Program Requirements.

J. ~~I.~~ The pricing and other terms and conditions of the Program set forth herein are subject to change at any time, with the approval of SRP's Board of Directors.

SERVICE CONTRACTS:

The Service Contracts will include, without limitation, the following terms and conditions:

A. The GSP must deliver sufficient firm energy, to the point of delivery agreed to by SRP, to meet the Customer's Total Load Requirements, on an hourly basis, for a period of at least one year. The GSP is responsible for procuring or providing transmission service to deliver the energy to SRP's delivery point.

B. Unless SRP directs the Customer to pay GSP invoices directly, SRP will pay the GSP for the energy delivered; SRP will bill the Customer for all amounts paid by SRP to the GSP.

C. SRP shall have no liability for any losses, claims, or damages arising from a default by the GSP or the Customer.

D. SRP will settle with the Customer for Energy Imbalance and other relevant costs monthly as specified in the "Customer Charges and Credits" section below.

E. The GSP must provide a separate monthly invoice for the energy delivered to SRP for the benefit of the Customer.

F. SRP will serve as the scheduling coordinator. The GSP must provide SRP with monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule in accordance with the Program Requirements.

G. SRP will apply all payments received from the Customer to services rendered by SRP before remitting any amounts to the GSP. The Customer will be solely responsible for any shortfall.

IMBALANCE SERVICE:

SRP will calculate Energy Imbalance for the Customer account.

A. Energy Imbalance will be settled as follows on an hourly basis:

   i. If Energy Imbalance is less than or equal to the greater of +/- 15% or 2MW (a "Tier 1 Energy Imbalance"), it will be settled at the applicable CAISO External Load Aggregation Point (~~LAP~~ELAP) price.

   ii. If Energy Imbalance exceeds the greater of +/- 15% or 2MW (a "Tier 2 Energy Imbalance"), then (i), if due to the hourly delivered energy from the GSP exceeding the hourly Customer Participating Metered Energy, it will be settled at 75% of the applicable ~~LAP~~ELAP price when the ~~LAP~~ELAP price is positive, or 125% of the ~~LAP~~ELAP price if negative, or (ii), if due to the hourly Customer Participating Metered Energy exceeding the hourly delivered energy from the GSP, it will be settled at 125% of the applicable ~~LAP~~ELAP price when the ~~LAP~~ELAP price is positive, or 75% of the ~~LAP~~ELAP price if negative.

B. If a Tier 2 Energy Imbalance occurs on more than 20% of the hours in a calendar month, there will be deemed to have occurred an "Excessive Imbalance." SRP will provide written notice to the GSP and the Customer of any Excessive Imbalance. If an Excessive Imbalance occurs two or more times within any rolling 12-month period, SRP may, in its discretion, terminate the Service Contract with respect to the GSP and cancel the Customer's participation in the Program, by providing advance written notice as set forth in the Service Contracts. Cancellation due to an Excessive ~~Imbalances~~Imbalance may result in SRP declaring the GSP ineligible for the sale of energy to SRP under the Program.

REPLACEMENT OF GSP:

If the Service ~~Contract~~Contracts with respect to the GSP ~~expires~~expire or ~~is~~are terminated, then until energy deliveries commence under Service Contracts with a replacement GSP, or the date on which cancellation of the Customer's participation in the Program is effective, SRP will provide Resupply Energy at the Resupply Price. If there is no effective Service Contract with a GSP for a period of 60 consecutive days, SRP may cancel the Customer's participation in the Program.

CANCELLATION:

A. If the Customer ceases to meet the qualifications, and satisfy all conditions and requirements, for participation in the Program, or fails to comply with the Service Contracts, SRP may cancel the Customer's participation in the Program by providing advance written notice as set forth in the Service Contracts. ~~The~~

B. If the Customer ~~must provide at least three years' advance~~delivers notice to SRP ~~to cancel~~cancelling its participation in the Program, then the cancellation will take effect 36 months after Customer's delivery of the notice of cancellation, or, if requested by the Customer, a sooner date agreed to by SRP if and when SRP determines, in its sole discretion, that allowing an earlier effective date would not adversely impact the costs or reliability of service to SRP's other customers. Any cancellation is conditioned upon the concurrent termination of the Service Contracts.

C. If ~~the Customer cancels its participation in the Program with less than three years notice, or if~~ SRP cancels the Customer's participation in the Program ~~(each, an "Early Termination")~~for any reason, then SRP will provide Resupply Energy at the Resupply Price, and all Program charges and payments will continue to apply, for the period of time between the effective date of cancellation and the date that is ~~three years~~36 months after notice of cancellation is delivered, or a shorter period specified by SRP if and when SRP determines, in its sole discretion, that reducing that period would not adversely impact the costs or reliability of service to SRP's other customers.

D. Any waivers or reductions of the 36-month periods referenced in subsections B and C above will be granted, if at all, in the order in which the Cancellation Notices are received or delivered, as applicable, by SRP.

CUSTOMER CHARGES AND CREDITS:

A. Customer's participation in the Program does not replace or reduce the charges incurred by the Customer under the Price Plan under which the Customer takes service, except as follows:

i. The Fuel and Purchased Power Adjustment Mechanism (FPPAM) component will not apply to the Customer Participating Metered Energy, subject to Paragraph E below; and

ii. The Generation (kW and Energy) component will not apply to the Customer Participating Metered Energy or Customer Participating Billing Demand.

B. The Customer will be assessed a monthly Buy-Through Charge of $4.15/kW of Customer Participating Billing Demand, to recover costs and charges incurred by SRP to maintain capacity reserves, administer the Program, and recover the Customer's share of Early Technology Adoption costs (costs related to certain existing renewable generating facilities on SRP's system).

C. SRP will charge the Customer for all amounts paid by SRP to the GSP.

D. SRP will charge or credit the Customer for the amounts associated with any Energy Imbalance, as calculated under the "Imbalance Service" section.

E. If, at the time of the Customer's enrollment in the Program, the FPPAM over- or under-collection balance exceeds $20 Million, the Customer will be assessed an FPPAM Settlement Adjustment (FSA) based on the Customer's pro-rata share of the FPPAM over- or under-collection balance.

i. The FSA will be calculated as follows:

FSA = F x (C / T)

Where:

F = FPPAM over- or under-collection balance in excess of $20 Million

C = Customer's energy usage during the period in which the FPPAM over- or under-collection balance accumulated

T = Total energy served by SRP during the period in which the FPPAM over- or under-collection balance accumulated

ii. The Customer will have the option to settle the FSA as a lump-sum credit or payment (as applicable), or in 36 equal monthly credits or payments.

iii. ~~If~~As of the date on which cancellation of the Customer's Program participation is ~~cancelled~~effective, SRP will reconcile the difference between the FSA and the amount that the Customer has already paid or has been credited. For purposes of that reconciliation, the Customer's pro-rata share of the FPPAM over- or under-collection balance (calculated as "C / T" in the formula above) will be the same percentage that was calculated at the time of the Customer's enrollment in the Program.

F. Any taxes or governmental impositions which are or may in the future be assessed based on gross revenues of SRP 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 will be applied to the Customer's bill.

APPENDIX B: ~~CUSTOMER PARTICIPATING LOAD AND CUSTOMER PARTICIPATION FACTOR~~Customer Participating Load and Customer Participation Factor

Methodology: During the initial Program enrollment period, SRP will determine for each Account the initial Customer Participating Load and Customer Participation Factor, as follows:

Step 1: SRP will determine the Account's Annual Peak Demand in the 12-month period immediately preceding the enrollment date (the "Baseline Peak Demand").

Step 2: SRP will make a preliminary calculation of the Account's Customer Participating Load, which will equal the lesser of (a) 100% of the Baseline Peak Demand, less the maximum demand participating in a Concurrent Program, or (b) 50 MW (the "Preliminary Participating Load").

Step 3: If the Preliminary Participating Loads for all Accounts total more than 200 MW (an "Oversubscription"), then SRP will determine each Account's Customer Participating Load using a pro-rata methodology based on the Baseline Peak Demand of each Account, per the timeline provided in Appendix C. Otherwise, the Customer Participating Load will equal the Preliminary Participating Load.

Step 4: SRP will calculate the Customer Participation Factor by dividing the Customer Participating Load by the Baseline Peak Demand.

After the initial Program enrollment period, SRP will process Program participation applications on a first come, first served basis. For Accounts enrolling after the initial enrollment period, the Customer Participating Load will be the lesser of the Preliminary Participating Load or available Program capacity.

SRP may review and re-calculate the Account's Annual Peak Demand on an annual basis. If the Annual Peak Demand for any year differs by more than 15% from the Annual Peak Demand figure used to calculate the then-current Customer Participation Factor, SRP may adjust the Customer Participating Load and Customer Participation Factor based on the updated Annual Peak Demand.

Examples: The following examples are intended for illustrative purposes only to demonstrate the calculation of the Customer Participating Load and Customer Participation Factor during the initial Program enrollment period.

- If there is no Oversubscription, the Account is not participating in a Concurrent Program, and Baseline Peak Demand is 45 MW, then the Customer Participating Load will be 45 MW, and the Participation Factor will be 100%.

- If there is no Oversubscription, the Account is not participating in a Concurrent Program, and Baseline Peak Demand is 55 MW, then the Customer Participating Load will equal 50 MW, and the Customer Participation Factor will be 91%.

- If there is no Oversubscription, the Baseline Peak Demand is 50 MW, and the Account is allocated 20% of the generation from a 100 MW solar facility under a Concurrent Program, then the Customer Participating Load will be 30 MW (50 minus 20), and the Customer Participation Factor will be 60% (30 divided by 50). However, if, under this example, the Baseline Peak Demand were 100 MW, then the Customer Participating Load will be 50 MW instead of 80 MW, due to the 50 MW cap.

APPENDIX C: initial Enrollment period

- 10/2/23 – 10/27/23: Customers must submit applications for eligible accounts
- 10/30/23 – 11/17/23: SRP will calculate and notify customers of their Customer Participating Load
- 12/1/23: Deadline for execution of GSP Contracts for SRP to begin receiving energy on 1/1/24. If the GSP Contracts are executed after this date, energy deliveries will commence as of the first day of the billing cycle that starts on or immediately after the 30th date after execution of the GSP Contracts.

Proposed Buy-Through Program

Effective January 1, 2024

Brian Koch & Adam Peterson| 8/10/2023

Agenda

- Buy-Through Program Overview
    - Statutory/SRP Requirements
    - Activity to Date
        - Stakeholder engagement meetings & buy-through website
        - Updates since first presentation to the Board
    - Program Design Overview
- Maintain System Reliability
    - Resource Adequacy and Energy Imbalance
- Avoid Cost Shift
    - Buy-Through Charge
    - Energy Imbalance and Resupply
    - FSA (FPPAM Adjustment Settlement)
- Next Steps

Statutory Requirements

A.R.S. Section 30-810. Buy-through program; terms, conditions, limitations; definition

A. On or before January 1, 2024, a public power entity that is an agricultural improvement district established pursuant to title 48, chapter 17 shall offer a buy-through program that both:

1. Includes terms, conditions and limitations, including a minimum qualifying load and a maximum amount of program participation.

2. Is structured to maintain system reliability and to avoid a cost shift to nonparticipating customers.

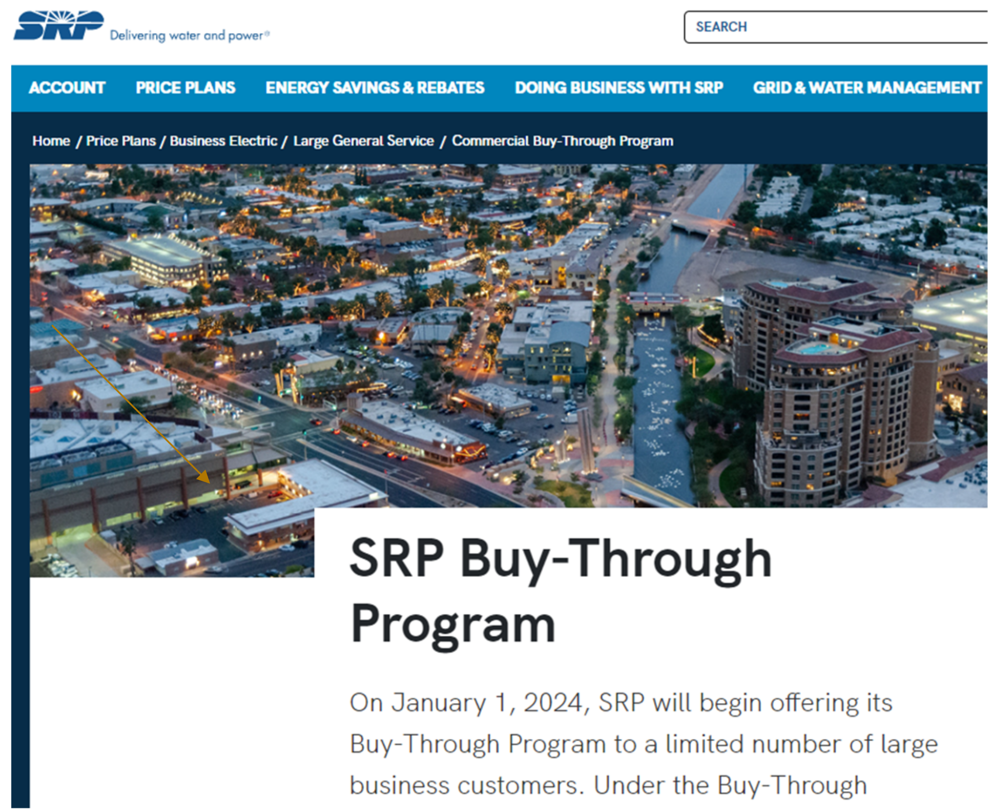
B. For the purposes of this section, "buy-through" means a purchase of electricity by a public power entity at the direction of a particular retail consumer, subject to the terms of the program.

Activities to date

DEC-MAY	JUN	JUL	AUG
✓ • Buy-Through Informational Session (F&B)	✓ • Buy-Through Preview – high level (Board)	✓ • Stakeholder mtg: Discussion & Feedback	✓ • Management Presentation, Board Consultant Presentation & Stakeholder Comments (Special Board)
✓ • Buy-Through Board Consultant hiring process (Board)	✓ • Announcement on SRPnet.com webpage	✓ • Board Consultant Report published	
✓ • Buy-Through Informational Session (CUP)	✓ • Board Consultant Informational Presentation (F&B)	✓ • Proposed Program updates	
	✓ • Stakeholder mtg: Program Overview		

Buy-Through Website
SRP.net/buythrough

- Overview of program/process
- Listing of key dates
- Access to key documents
- Instructions for engaging



Stakeholder Engagement Meetings

June 27th – Program Overview

- 37 attendees
- Discussions included:
    - Buy-through charges
    - FSA calculations
    - Aggregation not part of this proposal
    - Energy imbalance
    - Return to retail notice requirement
    - GSP delivery points
    - SEO program correlation

July 18th – Discussion & Feedback

- 33 attendees
- Discussions included:
    - Timing of adjustments to program
    - Subscription process and load growth
    - GSP delivery points
    - Timing of consultant report and proposed program changes
    - FSA calculations
    - Pay off dates of plants underlying ETA Charge
    - Loss factor
    - Marginal vs. embedded cost basis

Updates Since Initial Proposal

- Added option for SRP to allow accelerated “return to retail” and waitlist to return
- Reduced line losses from 4.14% to 3.32%
- Added details for enrollment process
- Changed 50MW cap to apply per-account and per-customer
- Added clarifying language throughout

Proposed Buy-Through Program Design Overview

Buy-through program - 200 MW of demand

- Minimum annual peak demand of 5 MW
- Minimum average monthly Load Factor of 60%
- Available to E-65 and E-67 customers

- Allows customers to access power from the market through a trilateral arrangement with SRP, a third-party Generation Service Provider (GSP) and the customer
- Allows customer to bypass most of SRP’s FPPAM and generation charges
- SRP will provide backup service should GSP fail to deliver

Maintain System Reliability

- GSP must meet all applicable legal and regulatory requirements
- GSP must provide firm capacity/energy
- GSP must meet SRP’s wholesale counterparty credit requirements
- SRP will continue to maintain Planning Reserve Margins for customer load
- SRP will continue its responsibility as Balancing Area Authority, will provide ancillary services, and energy imbalance services
- Customer must provide sufficient advance notice to return to standard service

Avoid Cost Shift

- Buy-Through price structure
- Buy-Through Charge
  - Reserve Capacity Charge
  - Early Technology Adoption (ETA) Charge
  - Administrative Charge
- Load-following Requirement
- Energy Imbalance settlement
- FPPAM Settlement Adjustment

Buy-Through Price Structure

Account will still receive one monthly bill from SRP

Remove:

- FPPAM
- Generation (kW and Energy)

Add:

GSP pass-through charges

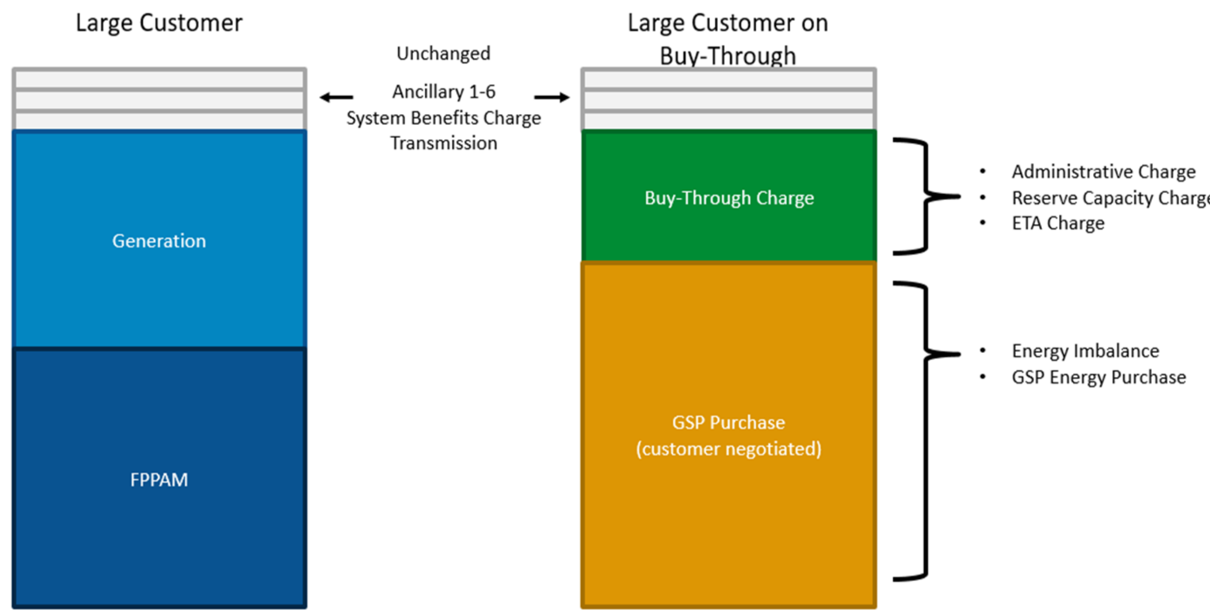
Buy-Through Charge $4.15/kW

- Administrative Charge
- Reserve Capacity Charge
- Early Technology Adoption Charge

Energy Imbalance settlements

FPPAM Settlement Adjustment (FSA)

- Option to settle as a lump sum or 36 equal monthly credits or payments



Fixed Monthly Service Charge, Meter Charge, EE Discount, Aggregation Discount, and Dedicated Distribution charges also apply to Buy-Through customers

Buy-Through Charge

Administrative Charge	$0.514
Reserve Capacity Charge	$2.871
ETA Charge	$0.764
	$4.149
Buy-Through Charge	**$4.15 / kW - month**

Administrative Charge

Startup Costs (IT, Consulting, SRP Staff)	$748K
Annual Startup Costs (Five Year Annualization)	$748K / 5 = $149.6K
Ongoing Annual Labor and Labor Overheads	$964.3K
Annual Buy-Through Administrative Costs	$149.6K + $964.3K = $1.1M
Annual Buy-Through kW	2,169,060
Administrative Charge	$1.1M / 2,169,060 kW = **$0.514 / kW-Month**

Reserve Capacity Charge

Reserves Ratio	
Planning Reserve Margin	16% of forecasted demand
Total Planned Generation Capacity	116% of forecasted demand
Reserves Ratio	16/116 = 13.79%
Class Share of Capacity Costs	
Class Share of Generation Capacity Costs	$132.1M
Class Share of FPPAM Capacity Costs	$38.0M
Class Share of Capacity Costs	$170.1M
Class Share of Reserve Capacity Costs	$170.1M x 13.79% = $23.5M
Class Annual kW	8,174,702
Reserve Capacity Charge	$23.5M / 8,174,702 kW = **$2.871 / kW-month**

ETA Charge

Cost of ETA Generation Capacity	$104.3M
Capacity Value Credit	($7.7M)
Energy Value Credit	($39.0M)
Carbon Free Premium Credit	($3.9M)
Projected Above-Market ETA Costs	$53.8M
Class Share of Projected Above-Market ETA Costs	$6.2M
Class Annual kW	8,174,702
Early Technology Adoption Charge	$6.2M / 8,174,702 kW = **$0.764 / kW-Month**

Energy Imbalance

- SRP will calculate energy imbalance hourly
- SRP will settle energy imbalance with the customer monthly
- Allowable hourly deviation of 15% or 2 MW (whichever is greater)
- Within allowable hourly deviation, settled at CAISO ELAP price (Tier 1 imbalance)
- Exceeds allowable hourly deviation, settled at CAISO ELAP price +/- 25% (Tier 2 imbalance)
- If 20% of hours in month experience Tier 2 imbalance, “excessive imbalance” occurs
- Second instance of excessive imbalance within a 12-month period may result in SRP canceling the customer’s participation

Resupply Energy

- If the GSP contract expires or is terminated, SRP will provide Resupply Energy at the resupply price
- Resupply Price = Palo Verde Peak or Off-peak Intercontinental Exchange Day Ahead index (or another comparable index selected by SRP if the foregoing index is unavailable), plus the greater of $10 per MWh (prorated for any partial MWh) or 10% of the index price

FPPAM Settlement Adjustment (FSA)

Only applicable when FPPAM balance is +/- $20M

Example (for illustrative purposes only):

12 MW Buy-Through customer with 82% Load Factor
FPPAM under-recovered balance equals $400M
FPPAM recovery balance = $400M - $20M = $380M
SRP retail energy served during period = 85,000,000 MWh
Customer energy used during accumulation period = 223,684 MWh

FSA = [FPPAM recovery balance] x [Customer energy usage during accumulation period / SRP retail energy served during same period]

FSA = [$380M x 223,684 MWh / 85,000,000 MWh] = $1,000,000 FPPAM Settlement

Option to pay over 36 months
Reconciled if customer returns to standard service

Next Steps

JUN

- Preview - high level (Board)
- Announcement on SRPnet.com webpage
- Stakeholder mtg: Program Overview

JUL

- Stakeholder mtg: Discussion & Feedback
- Board Consultant Report published
- Proposed Program updates

AUG

- Management Presentation, Board Consultant Presentation & Stakeholder Comments (Special Board)

SEP

SEP 18

- Last day to receive customer comments

SEP 26

- Management Final Recommendation & Board Decision (Special Board)

thank you!

[redacted]

Review of Management’s Buy-Through Pricing Proposal

for
Salt River Project Agricultural Improvement and Power District – Board of Directors

By

Mr. Bruce Chapman, Project Manager
Dr. Corey Lott
Dr. Daniel Hansen
Mr. Nicholas Crowley
Mr. Robert Camfield

July 27, 2023

800 University Bay Dr #400
Madison, WI 53705-2299

608.231.2266
www.CAEnergy.com

Table of Contents

Review of Management's Buy-Through Pricing Proposal

for

Salt River Project Agricultural Improvement and Power District Board of Directors

by

Christensen Associates Energy Consulting, LLC
July 27, 2023

EXECUTIVE SUMMARY

SRP's management team has developed a proposed Buy-Through Program that meets all the design criteria identified by the Board regarding the costing, pricing, and statutory requirements for a successful program. Most importantly, the program structure promotes full cost recovery from participants while offering them the opportunity to seek and acquire efficiently priced generation services.

The cost underpinnings of the buy-through design are sound.

- Embedded costs of delivery services are properly classified by cost-causative factor and appear to be allocated according to conventional principles.
- Generation services, where provided by SRP (imbalance and resupply) are based on sensible representations of marginal cost/wholesale market energy price.
- Ancillary services are acceptable in embedded cost form given the lack of reserves markets in the region.

Management's design offers pricing that recovers cost fully and is efficient.

- The design is consistent with the Board's general principles of gradualism, price efficiency, and revenue recovery.
- The design is consistent with sound utility practice and general economic theory:
  - Delivery services are priced based on embedded costs based on established costing methods. In particular, fixed cost recovery does not appear to take place via volumetric (kWh) pricing.
  - Generation services are based on market prices.
- Prices reflect their underlying cost drivers, by subfunction.

Lastly, the program's structure responds fully to the obligations of the legislation.

Management's approach to the key issues of buy-through pricing is largely sound, although we raise questions as to pricing methodology and eligibility/departure requirements.

- **Resource adequacy.** SRP's program provisions limiting scale, requiring detailed GSP vetting, tiered pricing of imbalances and resupply premium pricing all indicate that the program has multiple structures to support SRP being able to deliver generation to all its customers.
- **POLR consideration.** SRP plans to use public price indexes that allow the utility to match revenues from POLR customers to the cost to serve them.
- **Imbalance service charges.** SRP has chosen to settle imbalances with customers (rather than the GSP), using a tiered structure based on the utility's expectation that this will avoid or limit strategic scheduling based on forecasts of market prices relative to contract prices.
    - There might be opposition to the tiered pricing approach, but it appears to provide SRP with a necessary incentive to customers to minimize imbalances. The power to remove someone from the rate for persistent excessive imbalances is reasonable but arguably not sufficient.
    - The Tier 2 markup might be set at a level that makes SRP indifferent between customer imbalance increases and reductions. Observation of behavior early in the program may provide guidance here.
- **GSP Default.** SRP's use of the Palo Verde day-ahead price indexes plus a price premium appears to give customers using resupply service a strong incentive to recontract with a new GSP. The resupply price also gives customers the incentive to give SRP three-years' notice before returning to retail service.
    - There might be opposition to SRP charging a premium for resupply service. However, SRP is entitled to earn a premium in return for offering the service.
    - SRP's preference for Palo Verde appears defensible from both theoretical and operational perspectives.
- **Return to Standard Offerings.** SRP offers a clear path to return. The issue associated with return is the length of advance notice. Three years' notice is based on capacity availability concerns and planning experience. However, this may be conservative, and a policy of allowing a shorter time period in the event of availability may help to improve the attractiveness of the program.
- **Bypass.** The Buy-Through Charge is well documented and the calculations of administrative, reserve capacity and ETAC charges appear sound and defensible. As the program ages, reductions in administrative and ETAC charges should be expected.
- **Responsibilities of Contracting Parties.** SRP's program documents set out parties' responsibilities clearly. Aggregation is not currently feasible but can be considered in the future.
    - Ancillary services will be managed by SRP for sound reasons of lack of market sources. As markets develop, this could change without hurting the program.

Management's design appears to conform to industry practice based on a short list of examples.

- Examples from California and Nevada indicate that there is precedent for SRP's approach to limiting cost shifting.
    - California devised the Power Cost Indifference Adjustment (PCIA) to ensure that the out-of-market costs of energy resources would continue to be billed

to customers who secured power elsewhere. Their methodology does not need to be applied at SRP partly due to the relatively small scale of SRP's cost recovery and partly due to their more comprehensive view of generation value.

  - Nevada developed an impact-fee approach to valuation. Again, it has value as precedent for recovering out-of-market costs, but its methodology appears to be more complex than SRP needs, involving production cost simulations to estimate these costs.
  - FPPAM: it is difficult to find analogies but SRP's approach appears to be consistent with what other utilities do regarding fuel and purchased power costs.
  - ETAC: SRP's approach is simpler than the California and Nevada methodologies. SRP's approach has the advantages of transparency and likely ready acceptance. The possible disadvantage is that the approach does not attempt to evaluate the market value (and hence out-of-market cost) of the whole generation portfolio.

- Several aspects of the SRP design make use of similar design components at Arizona Public Service in its AG-X rate. However, SRP has adopted a different approach in some cases, partly due to differences in underlying rate design and pricing, and partly based on different perceptions about pricing incentives.
  - Both utilities include a reserve capacity charge to ensure that the lost customer loads continue to pay their share of reserve capacity costs, as the host utility is providing that reserve capacity.
  - Both utilities undertake imbalance settlement, but APS settles with the GSPs while SRP has decided to settle with the customers, based on the understanding that customer strategic behavior to minimize their costs can be influenced and reduced by a tiered pricing scheme.

Summary:

SRP management's proposed Buy-Through Program appears to meet the Board's requirements for a successful design: participating customers can contract with GSPs for service without introducing cost shifts to other customers, paying embedded costs for delivery services and market-based prices for generation services from their GSPs and from SRP through imbalance settlement and resupply pricing in the event of contract default. Customers may return to SRP under clear terms. Furthermore, the program appears capable of being scaled up and of responding to changes in wholesale markets, including with respect to alternatives to the provision of ancillary services.

1. INTRODUCTION

The management team of Salt River Project (SRP) has developed a Buy-Through Program that is intended to offer participating customers the opportunity to acquire electric energy from third-party generation service providers (GSPs). This pricing initiative responds to, and intends to fulfill, the requirements of new Arizona legislation with the express purpose of introducing buy-through at agricultural improvement districts in the state. The legislation is A.R.S. § 30-810, and it requires SRP to offer such a program to customers by January 1, 2024. SRP is entitled to specify conditions of service and limitations on eligibility such as minimum customer size and maximum participation. SRP is also required to offer buy-through service in such a way as to maintain system reliability and avoid shifting costs to other nonparticipating customers of the utility.

The Board of Directors of SRP (the Board) engaged Christensen Associates Energy Consulting (CA Energy Consulting) to review management's Buy-Through Program proposal with regard to its ability to meet several criteria. These criteria are:

- Consistency with the Board's retail electricity pricing principles,
- Consistency with sound utility practice and general economic theory,
- Success in reflecting cost causation, and
- Ability to meet the requirements of the legislation.

The Board would also like the review to compare the design with other rates intended to accomplish similar objectives of customer choice using efficient pricing and achieving revenue recovery.[1]

This report presents the results of our review. The next section summarizes management's proposed design. Our review of the design begins in Section 3, which examines the program's connections to its underlying costs. Embedded costs support the services that SRP will continue to provide buy-through customers. Marginal generation costs, in the form of wholesale market prices, provide the basis for retail prices that customers will pay for generation services that the GSPs do not provide. These come in the form of 1) imbalance charges, which occur as a result of the ongoing mismatch between GSP deliveries and customer consumption, and 2) resupply charges which apply in the event of GSP contract termination.[2]

Section 4 contains our review of the main program provisions. These include core aspects of pricing and structural provisions that set the terms of service. Section 5 reviews the program's approach to managing several issues that can arise in offering buy-through service. Section 6 compares SRP's design with other programs having some features similar to those of the Buy-Through Program. The closing section presents our findings.

[1] Salt River Project Board of Directors, *Request for Proposal No. V100405NCP*, Section 2.1.

[2] This occurs when no contract is in force (e.g., in the event of GSP default) or when customer participation is cancelled with less than three-years' notice. See SRP, *Program Requirements* document, Section V.

2. SUMMARY OF MANAGEMENT'S BUY-THROUGH PROPOSAL

SRP management sets out its Buy-Through Program proposal in three documents: a *Program Design* that serves as a draft tariff, *Program Requirements* providing operational guidance to prospective participants, and a *Program Overview*.[3] This last document contains a high-level description of the program, including what SRP expects to accomplish through their program design. Collectively these documents provide a description of a customer's, GSP's, and SRP's rights and obligations under the program. These documents also specify the retail charges that the participating customer will pay and how the program will operate on a day-to-day basis.

2.1 Program Plan and the Parties' Obligations

Program Eligibility and Limitations

The Buy-Through Program will be available for large general service customers in good standing with SRP that are currently being served on the E-65 and E-67 rates. The program's minimum qualifying load is 5 MW of annual peak demand and customers are required to have an average monthly load factor of at least 60%.[4] The proposed program participation cap is 200 MW of demand. Participating customers are required to give SRP a three-year notice to return to standard service under SRP's retail rates.

Customer Obligations

Customers participating in the program are responsible for finding a GSP to serve their participating loads. The GSP will deliver energy to SRP on the customer's behalf and all charges from the GSP for this energy will be billed to SRP on a monthly basis and passed directly on to the customer. The GSP is required to meet legal and regulatory requirements to be a wholesale energy supplier to SRP and must meet credit requirements.[5] The GSP is required to make an effort to match the customer's scheduled loads in each hour. Mismatches will result in imbalance energy charges and, in the event of excessive energy imbalance occurring two or more times per year, a termination of the contract.[6] SRP is not responsible for helping a customer find a GSP or a replacement GSP in the event of default by the current provider.

Management's plan for the initial program implementation on January 1, 2024, is to have a program enrollment period during which half of the program cap of 200 MW will be reserved for larger customers with demand exceeding 25 MW and the remaining half will be reserved for

[3] Formal titles: 1) Salt River Project Agricultural Improvement and Power District, *Buy-Through Program*, draft of 6/1/23; 2) SRP, *Program Requirements*, draft proposal 6/13/23; 3) Salt River Project Agricultural Improvement and Power District, *Proposal for SRP's Buy-Through Program*, Effective January 1, 2024, June 1, 2023.

[4] Terms such as annual peak demand are defined in the *Program Design* document. Annual Peak Demand is the maximum 30-minute integrated kW demand for the customer over the 12-month period preceding the customer's enrollment in the program or any recalculation periods.

[5] Specifically, the GSP must be a member of the WSPP and provide firm capacity and energy sales or exchange service under WSPP Service Schedule C.

[6] Excessive energy imbalance is further discussed in Section 2.4.

customers with demand between 5 and 25 MW.[7] Buy-through customers will have an obligation to fully participate in the program for loads up to 50 MW. Customers with demands that exceed the 50 MW per customer cap and customers that receive some energy under another SRP program, such as a renewable energy program, will be subject to partial-load participation. Management's proposal defines relevant terminology for partial participation in the Buy-Through Program and explains how partial program participation will be determined and how the program will operate for these customers.[8]

Customers will be given a pro-rated share of the available program loads if there is considerable interest in the program. (That is, they will only be able to partially participate in the program). After the initial enrollment period, additional customers will be considered for the program on a first-come, first-served basis. Once the program is fully subscribed, additional customers will be placed on a waiting list.

GSP Obligations

The GSP is required to meet the customer's full scheduled loads of a fully participating customer. For a partially participating customer, the GSP must supply a share of the customer's scheduled loads according to their "participation factor". The participation factor is determined at the time of enrollment and is based on the ratio of the customer's participating demand, as determined by SRP staff, to the customer's annual peak demand. For example, a customer that has eligible loads that exceed the per-customer cap of 50 MW will have a participation factor equal to 50 MW divided by their annual peak demand. For a customer that receives a set amount (e.g., 20 MW) of energy from another SRP program, SRP will subtract this amount from the customer's eligible demand to determine their participation factor. (For example, 60 MW of demand less 20 MW is 40 MW, and the participation factor would be 40 MW/60 MW = 67%). SRP will adjust the customer participation factor if the customer's annual peak demands change over the course of their participation in the Buy-Through Program.

SRP Obligations

SRP's first obligation is to offer the program in a timely manner, as required by the statute. Additionally, SRP is required to operate the program, including qualifying customers and GSPs. Implicitly, SRP must treat customers fairly under the general commitment of obligation to serve, including providing fair terms of admission, rules of participation, and discontinuance. SRP also is required to support metering and billing necessary to facilitate actual buy-through transactions.

Additional Contractual Obligations

Customers and GSPs have additional obligations in the Buy-Through Program.[9] Customers are obligated to find a single GSP to cover their loads. A GSP may serve multiple buy-through customers but must have a separate contract with SRP for each customer. GSP contract terms

---

[7] The initial program implementation is described in the *Program Requirements* document. SRP does not commit to maintaining this apportionment of the program for small and large customers over the course of the program.

[8] The *Program Requirements* document explains partial participation, including the Appendix, which provides examples of how a customer's percentage participation will be determined. Relevant terms are defined in the *Program Design* document.

[9] These are described in the *Program Requirements* document.

must be at least one year. SRP will enter into a service contract with customers for each of the participating service accounts. SRP will execute a separate service contract with the GSPs. These contracts must be in place at least 30 days prior to the commencement of customer service under the Buy-Through Program.

A customer must continually maintain contracts with a GSP during their participation in the program, but there may be a 60-day grace period between contracts, during which the customer will receive resupply energy from SRP. The GSP must bill SRP for the energy they deliver through the program on a monthly basis. GSPs serving multiple customers must provide SRP with a separate bill for each customer. As might be expected, GSPs must securely handle sensitive customer billing information.

SRP also reserves additional rights to ensure that the Buy-Through Program maintains the intended design through the course of the program's life.[10] SRP may cancel a customer's participation in the program if they cease to satisfy the requirements for the program, including situations in which there are excessive energy imbalances between the customer's scheduled loads and the GSP's supplied energy.[11] If a customer's participation in the Buy-Through Program is cancelled, they must wait one year to be eligible for the program again. SRP has the discretion to determine if there are any limitations on the program due to equipment availability and can require customers to upgrade metering equipment as needed. Finally, SRP is not responsible for any losses to the customer due to the default of their GSP or to the GSP as a result of the customer leaving the Buy-Through Program.

2.2 Buy-Through Base Rate Charges

A Buy-Through Program participant will bypass the generation and fuel adjustor charges from their retail rate but will continue to pay charges for monthly service, delivery, ancillary services, and system benefits.[12] Customers with partial buy-through participation will bypass the generation and fuel and purchased power adjustment mechanism (FPPAM) charges on their participating metered energy and participating billing demand and continue to pay on the non-participating portion.[13]

Participating customers must also pay an additional buy-through charge on their participating monthly demand, currently set at $4.15/kW.[14] This charge has three components designed to recover 1) the administrative costs of designing, implementing, and operating the Buy-Through Program, 2) the cost of including Buy-Through Program loads in SRP's Planning Reserve Margin

[10] These rights are described in the *Program Requirements* document.

[11] For example, if a customer's demand or load factor drop below the program minimum requirements, they would cease to satisfy to program qualifications.

[12] The *Program Overview* document explains which retail tariff charges are bypassed and which retail tariff charges the customer must continue paying.

[13] These terms are defined in the *Program Design* document. The participating billing demand is the customer's maximum monthly demand during the on-peak period, as defined in their retail tariff, multiplied by their program participation factor. The participating metered energy is the total metered energy multiplied by the customer participation factor.

[14] The Buy-Through Charge is set forth in the *Program Design* document.

(PRM) via a reserve capacity charge component,[15] and 3) an Early Technology Adoption Charge (ETAC) component. This last component covers the cost of SRP's legacy renewable generation assets that were procured between 2009 and 2012 on behalf of all customers to satisfy renewable generation portfolio requirements.[16]

2.3 FPPAM Balances

While participating customers will be excused payment of fuel and purchased power charges on participating loads, they will still be liable to pay or receive their share of accumulated FPPAM balances. SRP tends to go through cycles of over- or under-collection of FPPAM charges relative to their actual cost of fuel and purchased power costs. (The current status is under-collection.) To prevent cost shifting of under-collected FPPAM balances onto non-participating customers (or excessive crediting to non-participating customers in the event of FPPAM over-collection) SRP will charge (or credit, as appropriate) the buy-through customer based on their share of these balances through the FPPAM Settlement Adjustment (FSA).[17]

This FPPAM settlement will be performed only when FPPAM balances exceed +/- $20 million. A participating customer's FPPAM balances may be handled as a lump sum upon joining the Buy-Through Program or as equal installments over a 36-month period. Customers will be charged (or credited) a pro-rata share of the existing FPPAM balance corresponding to their entry date into the Buy-Through Program. The customer's share of total energy usage during the accumulation period associated with the balance is multiplied by the excess balance amount (i.e., the total balance minus $20 million). In the event that a customer's participation in the Buy-Through Program is canceled, SRP will reconcile with the customer any remaining FSA balances at the date of program departure.

2.4 Energy Imbalance Charges

In each hour, a customer's consumption, adjusted for losses, will not necessarily equal their GSP's injection of generation supply, creating hourly imbalances. SRP will settle the cash implications of such imbalances with the customer. Management's plan proposes that buy-through customers be charged or credited for energy imbalances according to a two-tiered system.[18] Imbalances that are within +/- 15% or +/- 2 MW (whichever is greater) of scheduled loads are considered Tier 1 imbalances, while imbalances beyond that threshold are deemed Tier 2.

Tier 1 imbalances are charged or credited at the applicable CAISO Load Aggregation Point (LAP) price. For example, an instance of Tier 1 oversupply by the GSP to the customer results in a

---

[15] This document also describes how SRP has based this portion of the Buy-Through Charge on capacity-related costs related to their generation and FPPAM rates from their 2019 Cost-Allocation Study.

[16] These early renewable investments involved costs that are currently considered to be above-market compared to the current costs of renewable power generation projects. SRP argues that the ETAC charge is essential to prevent the Buy-Through Program from shifting these costs onto SRP's other customers.

[17] The settlement process is explained in the *Program Overview* document and the calculation of the pro-rata settlement share is detailed in the *Program Design* document.

[18] Imbalance charges are detailed in the *Program Design* document.

credit by SRP to the customer of the load difference priced at the LAP price. (This credit reflects the anticipated change in SRP's revenue from either a reduction in cost of purchased power or increased revenue from the sale of the oversupply at the same market price. SRP is financially whole following the imbalance payment.)

Tier 2 imbalances are charged or credited according to the CAISO LAP price with a 25% premium or discount applied in SRP's favor, with the stated purpose of deterring large imbalances.[19] For example, an instance of Tier 2 oversupply (when the LAP price is positive) results in a credit to the customer at 75% of the LAP price. SRP's costs decline, or its revenues increase, by the full LAP price applied to the settlement amount.[20]

For a case of Tier 2 under-supply, the customer pays a premium price to SRP on the difference between energy used by the customer and delivered by the GSP, i.e., the entire difference, not merely the excess over the 15% threshold, is priced as Tier 2. In the case of sustained under-supply at times of high LAP prices, the customer would quickly find itself facing bill increases above the levels expected by their contract with the GSP.

Imbalance charges must be settled by the monthly bill's due date based on preliminary values, but SRP will perform a reconciliation using actual figures in subsequent months.[21] SRP also makes provision for customers who maintain "excessive imbalances," which are defined as occurring when at least 20% of the hours in a monthly billing period have Tier 2 imbalances. SRP will notify customers and GSPs of any months with excessive imbalances and SRP has the right to terminate the GSP's service contract and cancel a customer's participation in the program for at least two months of excessive imbalances during a rolling 12-month period. SRP may also make a GSP ineligible to participate in the program due to excessive imbalances.

2.5 Resupply Energy

SRP must provide participating customers with resupply energy in the event of default of the customer's GSP. Resupply energy pricing applies during periods in which there is no contract in effect between a customer and a GSP, or if a customer leaves the Buy-Through Program with less than three-years' notice.[22] During resupply energy periods, SRP charges customers using retail price based on the time-of-use (TOU) prices of the Palo Verde Peak or Off-Peak Intercontinental Exchange (ICE) day-ahead indexes (or any such replacement index if these become unavailable). SRP will apply a premium to the index prices that is the greater of $10/MWh or 10% of the index price.

---

[19] This premium means that over-supply will be credited at 75% of the LAP price while under-supply will be charged at 125% of the LAP price, in situations where the LAP price is not negative. For negative LAP prices, the premium will move in the opposite direction, i.e., convert into a discount. That is, over-supply will be charged at 125% of the LAP price and under-supply will be credited at 75% of the LAP price.

[20] SRP provides an example of the calculation that includes loss adjustment and rounding to the nearest MW to provide an exact representation of the settlement process. See their *SRP Buy-Through Program Overview* presentation at the July 18, 2023 stakeholders' meeting, available on their website: https://www.srpnet.com/price-plans/business-electric/large-general-service/buy-through#3, p. 9.

[21] This process is explained in the *Program Requirements* document. The *Program Overview* document describes the deterrent purpose of the Tier 2 pricing rule.

[22] Resupply energy is explained in the *Program Overview* and *Program Requirements* documents.

Resupply energy differs from imbalance energy in that it is expected to be used intermittently and for short duration, until the customer acquires a new GSP or returns to service with SRP. The TOU price structure can be quite volatile, based on historical Palo Verde prices, suggesting that customers will usually have a strong inducement to seek a new GSP contract.

2.6 Program Operation

Management sets out a process for day-to-day scheduling and delivery of energy as well as the process of billing.[23] The customer will provide the GSP with forecasts of their hourly loads. From these forecasts, the GSP determines their delivery obligation by multiplying the forecasted loads by the customer's participation factor and by adjusting for line losses.[24] The GSP is required to deliver energy to the delivery point (an SRP-approved 230 kV receiving station) and is responsible for all costs and regulatory obligations (e.g., CAISO requirements) before the energy reaches the delivery point. The GSP will provide SRP with the scheduled hourly loads (rounded to whole MW) for the month at least seven business days before the beginning of the billing month.

SRP will act as the scheduling coordinator, tagging the forecasted energy deliveries in accordance with the WECC Preschedule Calendar and entering the forecasts in the trade capture system.[25] The GSP, supplied by information from the customer, can update the forecasted loads as late as the (trading) day before scheduled deliveries. The GSP must provide physical path information, including all information about the path upstream of the delivery point, by this date as well. SRP also has the option, in emergency situations, to interrupt planned buy-through energy deliveries. If SRP must cut the GSP's energy due to system issues, they will not charge the customer for resulting energy imbalances.

The process for monthly billing and reconciliation is as follows: SRP will issue a bill to the buy-through customer by the second business day of the following month; GSPs have until the 10th day of the month to validate or modify tagged hourly delivered loads for the previous month; reconciliations will be made on future bills if necessary.

3. ANALYSIS OF SUPPORTING COSTS

3.1 Embedded Costs (Cost Allocation Study)

CA Energy Consulting reviewed the base tariffs of customers eligible for the Buy-Through Program, along with the Cost Allocation Study (CAS) that supports their prices, primarily for the purpose of evaluating the degree to which program participants will continue to pay their cost to serve. Failure to do so would result in cost shifting to other customers.

---

[23] The *Program Requirements* document provides a useful description of how energy scheduling, delivery, and billing will work in the program.

[24] The projected line loss multiplier is 1.0343.

[25] Additional details and requirements related to scheduling, not enumerated here, are described in the document.

Customers currently taking service under rates E-65 (Standard Price Plan for Substation Large General Service) and E-67 (Standard Price Plan for Large Extra High Load Factor Substation Large General Service) are eligible to apply for service under the Buy-Through Program. Both of these rate designs are characterized by functionally unbundled rate components. That is, each function of electric service is accorded a separate line or lines in the bill rather than being bundled into single conventional customer, energy, and demand charges. The rates have monthly facilities charges, per kW charges, and per kWh charges with disaggregation as follow:

Monthly Service Charge

- Billing and Customer Service
- Meter

Per kW Charge

- Transmission
- Ancillary Services (E-67 only)
- Generation (waived for Buy-Through Program participants)

Per kWh Charge

- Transmission (E-65 only)
- Ancillary Services (E-65 only)
- System Benefits
- Generation (waived for Buy-Through Program participants)
- Fuel and Purchased Power (waived for Buy-Through Program participants)

Provided that all generation-related costs are restricted to the generation and fuel line items, and that no other costs are incorporated into these line items, cost shifting will not readily occur.[26] Based on the line items above, and upon SRP's intention to provide transmission and ancillary services to buy-through customers, and upon the continuation of a system benefits charge applicable to total customer consumption, it appears that cost shifting is unlikely to be a problem, pending the analysis of embedded costs below.

SRP provided a recent CAS to facilitate review of the utility's cost allocation practices.[27] The study performs the familiar tasks of functionalizing, classifying, and allocating the revenue requirements of the utility to the various rate classes. The study that we reviewed combined large customers now served under rates E-65 and E-67 into a single class, denoted E-65. The study's schedules depict the utility's costs for the various functions and subfunctions (e.g., meters) and permits the reviewer to follow functional costs through to full allocation by class.

SRP also provided a rate design workbook that demonstrates how tariff prices are derived from the costs allocated by subfunction in the CAS. The workbook demonstrates that costs incurred by subfunction are included in the individual prices of that subfunction. Specifically, generation prices are based on generation-related revenue requirements and the appropriate billing

---

[26] Riders that recover costs that are excluded from the cost of service and base rates can also produce cost shifting. SRP has a number of riders applicable to E-65 and E-67 customers. None appear to present cost shifting potential in this case.

[27] Salt River Project, *Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the May 2019 Billing Cycle*, December 20, 2018.

quantities. The unbundled nature of the rate permits clear understanding of the absence of potential for cross subsidy based on tariff prices and the costs that they represent.

One obscure point worth mentioning is that SRP removed its Environmental Programs Cost Adjustment Factor (EPCAF) line item from the CAS and deposited some of those costs into the generation and fuel components of the bill.[28] As a result, the Buy-Through Charge applicable to participating customers includes a non-bypassable charge that permits continued recovery of these costs despite the elimination of the generation and fuel-related charges from the bill.

Another non-bypassable cost included in the Buy-Through Charge, the reserve capacity charge component, is designed to recover portions of the generation retail charge that are related to capacity-related costs for resource adequacy. SRP will continue to include buy-through customers in their capacity reserve margin to ensure resource adequacy on their system. Since these costs are not unbundled from the generation costs that SRP will avoid as a result of the Buy-Through Program, they seek to recover these costs via the Buy-Through Demand Charge. One alternative for future rate cases would be for SRP to unbundle their capacity-related charges from other generation charges for E-65 and E-67 customers for more transparency with respect to the Buy-Through Program design.

The use and level of a reserve capacity charge component has been an issue of some interest in a recent regulatory proceeding that includes their Arizona Power Company's AG-X tariff, the counterpart to SRP's planned Buy-Through Program. Testimony included review by one witness of whether the supporting utility should necessarily provide capacity or whether the GSP could be the provider. Another witness supported the utility's resource adequacy charge and recommended a level equal to 15% of the generation demand charge. This level is close to SRP's planning reserve margin of 16%, which results in a reserve capacity ratio of about 14% (reserves relative to generation including reserves).

In our view, the reserve capacity charge component is readily justifiable, both in principle and as an SRP charge (exclusively for now). The current absence of markets for reserves suggests that a financial cost-based charge offered by the supporting utility is simple, readily monitored by a regulator, and thus not injurious to any approximation to a competitive market that might emerge. Additionally, the capacity reserve level appears justified by SRP's operational rules and supported by the presence of a comparable measure at a neighboring utility.

In summary, it is possible to infer that the components of the rates that buy-through customers will continue to pay will recover costs associated with these functional components. In contrast, the bypassed retail generation and fuel rates include a mixture of costs that SRP will avoid as a result of the Buy-Through Program and costs that buy-through customers will continue to impose, which motivates the buy-through rate design.

3.2 Marginal Costs (Marginal Cost Study)

SRP provided CA Energy Consulting with a study of its marginal costs so that we could review it for information about the pricing of any aspects of the program that might use marginal cost, including imbalance and resupply pricing. The time pattern of the marginal costs of generation services appear to influence the seasonal and time pattern of pricing, as the tariff sheets

[28] Other costs were deposited in the fixed monthly charges and system benefits charge.

demonstrate. However, marginal costs do not appear to play a role in other aspects of the existing underlying rates. SRP's approach raised no issue since it appears in line with utility practice of setting relative energy prices with reference to relative marginal generation costs.

Nor do internal marginal costs figure in the pricing of imbalance and resupply services. These are based on market prices in some form: the CAISO Load Aggregation Point (LAP) prices for imbalance services and Palo Verde peak and off-peak price ICE day-ahead indexes in the case of resupply. In both cases SRP is engaged in applying prices to relatively short-notice purchases and sales in the regional wholesale market to balance customer needs with GSP energy provision. Market-based prices help SRP match its revenue recovery with the incremental/decremental costs of the customers' consumption.

SRP takes the position that market-based pricing is an appropriate approach to take in pricing these services. It is difficult to think how imbalance services could be priced in any other way. However, critics might suggest that resupply services could or should be priced on an embedded cost basis, placing buy-through customers on the same pricing basis as full-requirements SRP customers. SRP management believes that this argument is not correct because buy-through customers are not contractually similar to other customers. Buy-through customers have acquired access to capacity through their chosen GSP. The termination of that service does not grant the customer immediate access to SRP's generation capacity. While SRP continues to charge buy-through customers for reserve capacity, it is not charging for base, firm power-supporting capacity. That is the responsibility of the GSP. This implies that generation services ought to continue to be provided on the basis of market prices. CA Energy Consulting concurs with this argument.

SRP also believes that the use of the two different sets of prices is required by differences in the services required and in the nature of these prices. In the case of imbalance services, service provision is intended to occur on an ongoing basis in (normally) small increments or decrements relative to scheduled amounts. From an operational perspective, imbalance pricing benefits from local prices reflecting current market conditions and available on an hourly basis, if possible. The LAP prices fit that need.

For resupply services, on the other hand, SRP must step in with supply on a whole-load, likely multiple-day basis to cover a GSP default or some similar contractual breakdown. Although not hourly in frequency, the current Palo Verde indexes for peak and off-peak pricing periods offer a day-ahead benchmark for customer planning, a vital tool in risk management.

SRP also found that the Palo Verde prices were systematically higher on average than the LAP prices.[29] The Palo Verde price indexes, which reflect the price of WSPP Schedule C firm power, better reflect capacity costs compared to the real-time CAISO LAP prices. Firm power is more relevant to SRP's obligation to provide resource adequacy for customers during resupply. Moreover, the Palo Verde prices, in addition to the attributes mentioned above, suggest that they might prove to be a useful risk hedge for SRP and its non-participating customers. This point is especially relevant if SRP is confronted with systematically higher prices while trying to acquire

[29] See the Appendix for more information about the differences between the Palo Verde ICE day-ahead peak price index and the Palo Verde real-time hourly LAP prices. The Palo Verde ICE day-ahead prices are not shaped to hourly settlements and are fixed across the on-peak period (hours ending 7 to 22). This results in the day-ahead prices being higher during most of these hours. However, they may be lower than the real-time prices during one or more hours in which the system loads peak and reserves are low.

resupply power at short notice, for potentially long periods, and covering large volumes of energy for the affected customer(s).

In the next section, the report reviews from an economic theory perspective pricing issues that arose in our review of SRP's buy-through pricing approaches. From an operational perspective, though, the program's imbalance and resupply pricing plans appear sensible.

3.3 Ancillary Services

Ancillary services are provided by generation facilities and are vital for the reliable delivery of electricity services to consumers. Ancillary services include energy services, referred to as imbalance services, and non-energy services including operating reserve and non-reserve categories. Operating reserves constitute the share of operating capacity held as reserve supply, available on short notice in response to changes in total system demand.

SRP's retail charges for non-energy ancillary services are based on the average financial costs of selected generation facilities which provide such services, and are strongly driven by total system loads. Within the proposed Buy-Through Program, SRP's approach regarding ancillary services is to charge average cost-based ancillary service prices, as posted in the relevant retail tariff, on the total loads of participating customers, including load served by GSPs.

Because the costs of ancillary services are a function of system loads, and system loads are unlikely to be greatly affected by the availability of buy-through pricing, SRP costs of non-energy ancillary services will remain virtually unchanged regardless of whether energy is provided by SRP's internal generation portfolio, or the resources employed by GSPs to serve buy-through transactions.

From this perspective, it appears that SRP's approach to pricing and cost recovery of ancillary services from participating customers achieves the objectives of full cost recovery and comparable pricing with customers on the underlying rates. Note that this is true even though the pricing of ancillary services differs across these rates (per kW pricing for E-65 and per kWh pricing for E-67).

4. THE PROPOSED RATE'S ABILITY TO ACHIEVE DESIGN OBJECTIVES

The Board's seeks a review of the proposed Buy-Through Program with respect to several criteria for successful design:

- Consistency with the Board's general principles,
- Consistency with sound utility practice and general economic theory,
- Ability to reflect underlying cost drivers, and
- Compliance with the enabling legislation: A.R.S. § 30-810.

4.1 Consistency with Board Principles

The Board's general principles for successful rate design, as presented in the Request for Proposal, require:

- ***Gradualism:*** avoidance of large customer bill impacts arising from changes in retail prices or in rate designs.
- ***Relationship of prices to underlying costs:*** basing the prices of each rate on the underlying cost to serve such customers, with the consequence that other rate classes and water rates are not encumbered with the electricity costs of new rate design.
- ***Customer choice:*** striving to offer diverse customers rate options that meet their needs, including, in this case, the option to seek generation services from third parties.
- ***Equity:*** treating customers with similar cost to serve with similar pricing and billing, such that rates are perceived as being fair to all.
- ***Revenue Sufficiency:*** ensuring that the revenue requirement associated with a class of customers is recovered fully via rates, thereby minimizing the likelihood of cost shifting.

Management's proposed Buy-Through Program appears to satisfy the Board's criteria. With respect to the relationship of prices to underlying costs, the previous section of the report documents that SRP's unbundled rates E-65 and E-67 have charges that correspond to each of the subfunctions of SRP's electric services and that cost recovery of each subfunction is achieved with each of the corresponding prices. In addition, SRP's Buy-Through Charge fully collects the administrative costs of the program, assuming that the program is fully subscribed. Additionally, this charge makes provision for capacity-related charges that the participating customers would bypass, and recovers each customer's responsibility for early technology adoption of renewable generation facilities (ETAC costs).

The new rate option enhances customer choice by definition: customers hitherto required to take power from SRP by virtue of their location within its service territory will now have an opportunity to "shop" for generation services, a choice that has been available in some other U.S. jurisdictions for several years. The increase in customer choice is restricted to large customers on the two underlying rates and by the fact that not all those who apply for choice may be granted it. At present, this is not a material limitation, as SRP is opening customer choice to those customers most likely to be able to manage the extra contractual and risk management burden of energy management and choice of provider. Earlier offerings of customer choice in other jurisdictions made use of the same strategy of offering choice first to larger customers.

Management's plan also satisfies equity considerations in the sense that non-participating customers who continue to receive generation services under E-65 and E-67 pay the same charges as before and as are paid by participating customers for all services except for generation. This satisfies the traditional objective of like customers paying like amounts.

Lastly, the plan provides for revenue sufficiency with respect to participating customers. They pay SRP fully for non-generation services, reimburse their GSPs through SRP for generation services, and resolve imbalance issues in a manner that does not burden SRP with financial obligations. The program's costs and non-bypassable costs are fully incorporated in the Buy-Through Charge. Additionally, in the event of default, it appears that neither current customers of SRP nor SRP itself are exposed to increased costs, due to the provisions of resupply pricing.

4.2 Consistency with Sound Utility Practice and Economic Theory

Management's plan is consistent with sound utility practice, not simply from the costing and pricing principles espoused above by the Board, but also by virtue of the program's operational practices in developing the program and prospectively offering service under its provisions. The program documents specify the terms of customer entry and departure. The program reserves space for both smaller (25 MW or less) customers and larger, and specifies how customers with loads in excess of 50 MW will have their partial program participation determined. However, it does not specify fully how the *initial* customer selection will occur should the program be over-subscribed.[30]

Management has also detailed operational aspects of scheduling, price provision, and billing sufficiently to enable participating customers and GSPs to understand the mechanics of scheduling loads, delivering, and paying for them. Customers schedule loads for the coming month a week before the start of the month. SRP's and the GSP's responsibilities are clearly defined. The billing implications of imbalances are clearly explained as well. However, pricing aspects of the design of imbalance service charges deserve further review, which occurs in the issues section below.

The Buy-Through Program plan also makes provision for both customer departure prior to contract completion and the departure of a GSP. These provisions also raise issues:

- Customers must provide three years' notice of departure from the program. Is this duration necessary?[31]
- Default by a GSP results in a customer relying on SRP for resupply energy until they can find a new GSP. If they fail to find one, they face a wait of three years to rejoin SRP's retail service, unless SRP waives this requirement due to their conclusion that resources are adequate to provide firm service. Is the pricing plan appropriate for this situation or should it be modified?

The next section discusses these issues.

Management has also engaged prospective participants in briefings soliciting their response to the program design. Presumably, material concerns will receive management review in time for the January 1, 2024 start date should any changes be desirable.

With respect to economic theory, management's program aligns well with economic theory and the general principles of rate design. Of the main functions of a utility, delivery services are usually viewed as natural monopolies while generation services, including both production and the retail provision of energy, are viewed as workably competitive. Traditional vertically integrated utilities under regulatory supervision are still regarded as a viable means of providing electricity, but deregulation of generation services is now common.

Management's design is similar to rate designs found in deregulated markets in that delivery services are still to be provided by the regulated utility (SRP) while generation services are to be provided under competitive conditions. The proposed structure departs somewhat from the

---

[30] SRP management has stated that they would prorate the participation factors for all customers.

[31] SRP has stated that they intend to add language to their program documents stating that they will attempt to acquire the necessary capacity in less time, if possible.

market model found in organized transmission jurisdictions elsewhere in the U.S. in that SRP will retain provision of ancillary services, and transmission services will continue to be billed under the regulated utility's authority. Consistent with this arrangement, SRP will act as the scheduling coordinator; the market model typically designates an RTO or ISO to carry out these functions.

The proposed structure reflects current conditions in Arizona, which is to be expected in that the state is not yet fully operating under an RTO/ISO framework. The proposed structure appears appropriate at present and can be readily modified to suit future developments in wholesale markets.

It bears repeating that we concur with management's position that the pricing of imbalance and resupply services comports with economic theory in that SRP is providing services incremental to or temporarily supplanting generation services provided by the customer's chosen source of both firm energy and capacity. Market prices – separate from the utility's embedded cost-based prices designed to recover the costs of supporting full-service customers – are the appropriate metric for pricing.

4.3 Reflection of Cost Drivers

Management's proposal relies on the same representation in retail prices of cost drivers as the underlying tariff for all but generation services. Since SRP's CAS and rate design for these tariffs closely tie subfunctional costs to prices of those services, and the prices largely use the appropriate representation of the cost driver (e.g., demand charge for recovery of demand-related costs) the proposed design begins with solid grounding in appropriate pricing of costs.[32]

The remaining prices, for generation with respect to imbalances or resupply, largely reflect SRP's costs of buying or selling power at short notice, subject to the discussion of the issues below. From this perspective, the proposed Buy-Through Program effectively reflects cost drivers in its prices.

4.4 Compliance with Legislation

Management's proposal fully complies with the terms of A.R.S. § 30-810. Specifically, SRP intends to provide a Buy-Through Program in a timely manner that clearly specifies the terms and conditions of service for program participants, both customers and GSPs, including minimum customer load and maximum program participation. The design has readily discernible implications for cost recovery and is unlikely to generate cost shifting to SRP's other customers or the utility as a whole. Furthermore, there appears to be no threat to system reliability in the short run due to imbalance issues or in the long run due to customers shifting back to SRP. The design deters customers from no-notice changes in status, charges customers for reserve

[32] Reviewers of the E-65 and E-67 tariffs will note differences in price configurations and relative emphasis on demand-based revenue collection. The very high load factors of E-67 customers cause differences in price perception between the rates. The need for E-67 customers to control peak demand appears less since consumption fluctuates relatively little over time. In contrast, E-65 customers arguably perceive a more forceful influence on restraining peak demand, focused on hours when they near their peak demand level.

capacity as if they were still with the utility and has provisions for GSP default that induce customers to seek out a new GSP promptly.

5. POTENTIAL ISSUES ASSOCIATED WITH THE PROPOSED RATE DESIGN

5.1 GSP Resource Adequacy

Management's plan to ensure GSP resource adequacy has several components: controls on GSP eligibility, a limit on the scale of customer participation, rules for scheduling and related operational reliability, and a price incentive to minimize imbalances. Limitations on GSP eligibility are appropriate: legal and regulatory requirements to sell wholesale energy to SRP for any purpose, ability to deliver subject to the firm capacity and energy requirements of WSPP Schedule C, and an ability to meet SRP's counterparty credit criteria. In brief, a GSP must meet standard business requirements for participation in wholesale markets and making associated sales to retail customers.[33]

The program design also specifies scheduling requirements for customers and GSPs to ensure that the GSP can acquire power requested formally by the customer and can arrange for delivery to SRP. The Program Requirements document sets out in some detail the scheduling requirements for these parties, and these requirements indicate that SRP schedulers will be involved in an ongoing basis in ensuring compliance.

The design recognizes the inevitable presence of imbalances in the course of daily operations and the management proposal relies on a price premium relative to LAP prices to induce customers and GSPs to follow schedules and to avoid the accumulation of systematic imbalances. The size of the premium is the subject of discussion below. However, for purposes of this section, the proposed design seeks to use the premium structure as a price-based inducement for closely matching demand and supply on an hourly basis.

Even in the case of default, when the GSP is clearly not providing adequate resources, the program plan makes it likely that SRP will be able to obtain resources necessary to provide resupply energy for the customer.[34] Additionally, the premium of the Palo Verde ICE day-ahead price index over the real-time CAISO LAP prices reflects SRP's need to obtain firm power and signals that valuation to customers. Furthermore, the presence of the reserve capacity provision in the Buy-Through Charge is designed to reflect SRP's commitment to secure the resources to ensure available capacity, while assuming that energy is likely to be secured in the wholesale market as a result of that capacity. We comment further about Palo Verde price patterns below.

Taken together, these measures minimize the likelihood that GSP resource adequacy will be an issue in the short and long run.

---

[33] See the *Program Overview*, p. 5.

[34] SRP notes that any liquidated damages arising from the default will be paid to the customer, since SRP will have recovered its supply costs via the resupply price mechanism.

5.2 Provider of Last Resort Considerations

SRP will need to act as a provider of last resort (POLR) in the event of GSP default. Management's plan not only strives to minimize concerns about GSP resource adequacy and viability, but the proposed design also provides for resupply pricing as a POLR pricing structure. Reliance on a publicly available price index at a nearby location characterized by a large volume of transactions offers a reliable basis for contracting at short notice. Such pricing should satisfy several criteria, including freedom from controversy, price transparency, and ready availability. The price premium and potential variability of prices will provide a strong inducement to customers to keep the period of resupply price exposure short.

5.3 Imbalance Service Charges

Imbalance services constitute a settlement procedure to reconcile actual vs. forecast quantity differences. Such mechanisms are common features of commercial trade and are particularly applicable to energy and financial markets. Well known examples in energy markets include:

- The dual settlements procedures of unbundled electricity markets organized under ISOs/RTOs settle actual vs. day-ahead load differences according to real-time energy prices.
- Two-part tariff options common to retail electricity markets settle differences between actual and projected loads according to short-run marginal cost-based prices.
- Contracts for differences (CfDs) applicable to commodity markets settle actual vs. forecast price differences on defined contract quantities.
- Fuel adjustment charge mechanisms common to retail electricity services settle actual vs. projected fuel price and sales quantity differences.

In short, provisions to settle actual vs. projected differences are integral to workably competitive markets. Accordingly, the inclusion of imbalance charges in SRP's Buy-Through Program appears to be on solid ground. In addition, the settlement mechanism of SRP's proposed Buy-Through Program gets much right.

Quantity Differences are measured in hourly frequency. It is important to meter differences in high frequency. First, the hourly loads of participating customers will generally have higher variation than system level loads and vary substantially among participants. Thus, hourly variation is important in order to accurately capture the cost responsibility of individual loads to cost levels of SRP and, to a lesser extent, regional markets. Second, long time intervals can conceal short-term differences between actual and forecasted values: netting balances across time will cause under-representation of SRP's costs of providing imbalance services.

Net monthly charges reflect actual vs. scheduled differences, including charges for quantity supply shortfalls (actual < scheduled) and credits for quantity supply surpluses (actual > scheduled). Settlement costs are likely to be much higher during times of high system loads. Hence, with settlements in hourly frequency, participating customers have incentives to realize quantity supply surpluses but not excessive surpluses, reflected in net bill credits.

Actual vs. scheduled quantity differences, settled at marginal costs, are also measured in hourly frequency. SRP's proposed approach to determining imbalance charges will settle quantity differences at marginal costs, measured as the real-time dispatch (RTD) load aggregation point (LAP) prices for the Salt River balancing authority.

One difference with respect to SRP's imbalance pricing plan compared to other buy-through programs in Arizona is that settlement is to occur between the customer and SRP rather than between SRP and the GSP. SRP selected this approach because their research indicated that GSPs tend to deliver scheduled amounts with precision regarding timing, location, and amount, barring transmission constraints outside SRP's service territory. On the other hand, the natural variability in customer loads is complicated by some customers' ability to strategically over- or under-schedule to reduce their costs.

The basis for such behavior is that the (presumably) fixed price of their scheduled generation charges from their GSP may exceed or be less than the imbalance price that SRP uses. Customers rapidly acquire the ability to forecast LAP prices, having access to weather and market price data for their region. If low LAP prices are expected, the customer can reduce their bill by under-scheduling and purchasing the load shortfall from SRP. If widely practiced, strategic behavior leads to systematic and increasing swings in imbalance totals. A price premium/discount for excessive imbalances always in SRP's favor will provide an incentive to mitigate the size of such imbalances and encourage truthful revelation of scheduling plans.

Viewed in this light, the price incentive applicable to extreme imbalances, backed by the power to discontinue service in cases of persistent imbalance, appears to be wholly appropriate. We support the proposed imbalance settlement and pricing system, including the use of premium and discount pricing to deter strategic customer behavior.

One might question management's plan to impose the 25% premium/discount level in SRP's favor for large imbalances. From the perspective of economic theory, the percentage ideally would be set high enough to make SRP indifferent between whether a customer exceeded the Tier 1/Tier 2 boundary or not. We anticipate that experience during the first year or two of the program will help to determine whether the premium/discount percentage should be altered in the future. Since the size of the percentage may act as a deterrent not only to strategic behavior but to participation on the basis of heightened bill risk, we suggest that SRP investigate this question in the future. Not yet acquired knowledge of customer preferences and the cost and frequency of imbalance ought not to delay program roll-out.

5.4 Default by the Customer's GSP

Management's plan for cases of GSP default (or customer early departure from the program) involves provision of resupply energy using pricing based on Palo Verde ICE day-ahead price index values. This plan is sensible, since it sets the energy price for short-notice transactions based on a publicly available market value, providing a clear signal to customers, and holding non-participating customers harmless, assuming that SRP's power acquisition costs are close to those of the index values. This approach is similar to POLR pricing in other jurisdictions, being based usually on wholesale market valuation of generation services.

Management's plan permits SRP to charge a resupply customer based on a wholesale price location at which the utility can obtain power, minimizing risk to the utility. The price premium helps to ensure cost coverage. In contrast, a customer might compare the pattern and level of SRP's resupply prices, as derived from Palo Verde ICE day-ahead indexes, with the pattern and level of hourly EIM prices and wonder whether SRP's pricing is fair. (See the Appendix for discussion of historical price patterns.)

With regard to average level, SRP management maintains that the revealed difference in level reflects the difference in power firmness and regional power availability. As noted previously, SRP can provide ongoing imbalance services with low-volume trades in the imbalance market. In contrast, obtaining firm power for resupply requires access to the relatively high-volume Palo Verde ICE day-ahead index prices and market. Operationally, then, the difference in level between these two markets ought to be reflected in the pricing of resupply services.

With regard to pattern, a customer might express concern that their usage pattern is priced at TOU period average prices, while the EIM reveals that they consume power that in a manner is relatively inexpensive compared with the average within each TOU period. The difficulty for SRP is that it is difficult to translate their perceived lower cost to serve based on hourly prices into actual lower cost purchases, since the utility must purchase at the index prices. The potential for inequity across customers exists: equal pricing but unequal costs. A scheme of price "shaping" might improve equity across customers, provided that the price premium could cover total resupply energy costs.

This equity improvement would be purchased at the cost of price complexity in that SRP would need to acquire CAISO hourly shaping factors, which are available daily, and price each resupply customer's load on this basis. While feasible, developing such a system, often for a single resupply customer, seems not to be cost effective since, regardless of shaping, SRP must acquire power at the index prices. Additionally, price shaping in the presence of price volatility, creates the possibility that a customer would find that a single hour at a time of high EIM prices is priced at, say, $1,000/MWh. If their actual load in that hour was high, their risk exposure would be magnified by price shaping. In brief: the customer would be on day-ahead real-time pricing without hedging capability. The TOU pricing scheme offers a partial hedge against price spikes in the EIM by avoiding shaping based on EIM price pattern.

One might also be concerned about the proposed markup: the larger of 10% of the index price or $10/MWh. Since the firm prices of the Palo Verde ICE Day-ahead price indexes are consistently higher on average than the CAISO LAP real-time prices, the need for a markup might appear questionable. Arguably, though, this premium simply represents the premium that a utility is entitled to charge for procurement of retail energy at relatively short notice. This is not a service that ought to be offered for free. Supporting this perspective is the use by other jurisdictions of price premium values. Notably, Arizona Public Service's buy-through resupply price includes a premium of $10/MWh.

In summary, the resupply price should provide for cost recovery by SRP, minimize the likelihood of cost shifting to other customers, and encourage customers using resupply pricing to plan for and obtain longer-term generation supply, either through a new GSP or through a return to their original SRP rate design. Experience with this component of the design during the first few years of the program will provide a basis for subsequent review.

5.5 Return to Company Standard Rate Offerings

Closely related to the issue of resupply price is that of management of customers who use resupply pricing. This pricing can apply due to a customer's GSP defaulting and to the customer departing the Buy-Through Program at shorter notice than the required three years, either by choice or due to violation of the program rules. Such pricing is intended to apply for a limited period of time, to allow the customer to find a new GSP or to return to their standard SRP rate.

5.5.1 Length of Advance Notice of Cancellation

The main issue additional to the pricing issues described above is associated with the duration of notice for departing the Buy-Through Program that the customer must offer in order to avoid these prices. The duration reflects SRP's perception of the time that it requires to secure capacity for the customer who has been outside the SRP system.

One issue with this position is whether a customer who has departed the system truly ceases to figure in SRP's capacity calculations and, therefore, whether SRP would need to acquire capacity were the customer to return. SRP's stated timeline for developing new capacity is three years.[35] Inquiry about this timeline yielded management views that SRP would no longer have access to the capacity included in the canceled GSP contract. While it might appear that such capacity would instantly become available, SRP cannot presume that it would be able to acquire the newly available MW. Currently tight markets lead the utility to expect that capacity might be available, but only at a high price or not at all. A cancellation just before the summer peak season would be particularly difficult for SRP to manage.

If this is the case, SRP would be right to be cautious. As the rule stands now, the three-year notice rule is mandatory. SRP could modify the rule to state that advance notice could be from one to three years, depending upon SRP's ability to secure capacity to serve the returning customer. This flexibility might improve the attractiveness of the Buy-Through Program by reducing a potentially significant barrier to participation. A customer who joins the program expecting to save money on generation services costs but has a contract that includes flexible pricing to some degree might be more willing to participate, or more willing to sign a flexibly priced contract in the first place if the door to returning were open with shorter notice.

Alternatively, SRP could offer shorter notice in return for interruptible service for all or a portion of the customer's load. The viability of such a strategy might depend on the likely availability of even non-firm power. If the summer peak season is characterized by chronically low capacity reserves, such an arrangement might not be feasible, as the customer would have to expect extended outages.

It should be noted that the APS Buy-Through rate requires just one year's advance notice of departure. However, that utility's perspective on capacity inclusion in planning may well be different from that of SRP, so it is not certain how comparable the advance notice settings are.

5.5.2 FPPAM Settlement Adjustment of Returning Customers

As we describe in Section 6, the proposed FSA is consistent with the treatment of directly served customers in other jurisdictions. While management's proposal is appropriate for the current circumstances (i.e., the beginning of the buy-through program, at a time with significant FPPAM balances), management may eventually need to consider symmetrical treatment for customers returning to SRP for full requirements service. That is, a customer returning to SRP will not have

[35] Reported in a conversation with SRP management.

been responsible for the FPPAM balance at that time and thus should not be responsible for paying / receiving credit for it. A possible method for treating returning customers in a consistent manner as departing customers would be to calculate the customer's load share of the current FPPAM balance (as management proposes for departing customers) and establish the resulting amount as a balance against which ongoing FPPAM charges are assessed.

For example, if a customer rejoins SRP when there is a +$50 million FPPAM balance, the customer would be assigned their load share of that balance (using the customer's historical loads) and the resulting amount would be established as a credit against which the ongoing FPPAM charges would be applied. Under this method, the customer would be assessed the FPPAM charges immediately upon returning to SRP, but they would only affect their total bill amount after the customer's share of the upon-return FPPAM balance is exhausted. The same methodology can be applied to an FPPAM overcollection scenario, which would prevent the rejoining customer from benefiting immediately from the FPPAM balances accrued during their absence from the system.

5.6 Cost Avoidance and Bypass

As previously discussed, the Buy-Through (Demand) Charge is designed to recover administrative costs associated with the Buy-Through Program as well as some of the costs embedded in the generation and FPPAM prices that might improperly be bypassed under the Buy-Through design. The costs retained in the new rate design's Buy-Through Charge include reserve capacity and ETAC price components, which represent the participating customer's ongoing obligation to pay. This approach seems reasonable, although one potential issue relates to the ETAC component.

SRP assesses the customer's obligation at the start of buy-through service and converts that to a lump sum obligation for immediate settlement or liquidation over the following 36 months. A customer who returns before the 36 months have elapsed receives a similar settlement undoing the remaining months' obligations. This approach appears neutral to the outcome of a customer who remains on the underlying rates.

The issue has to do with timing as the program evolves. ETAC obligations change over time, as the generation facilities age out and depreciate fully. SRP has not yet formally indicated its approach to how the valuation might change, but considers that revision during each rate application would be practical.[36] This should not delay program implementation, but SRP might want to set out plans for revaluation early in the program.

A related issue is the updating of the administrative component of the Buy-Through Charge. This is created to recover program set-up and ongoing administrative costs. Presumably the set-up cost recovery, which is spread over the program's first five years, would be terminated following that interval, assuming full subscription. (Ongoing costs would, presumably, be revised over time to ensure that the charge fully recovers these costs.)

Some might note that utilities frequently distribute the set-up costs of a program across all customers to avoid deterring participation. An example is the introduction of time-of-use options, where the incremental metering, billing, and administrative costs could have reduced

[36] From conversation with management.

participation to near zero. The justification for the policy of system-wide allocation was that all customers would benefit from the reduction in system costs by the shifting of participants' loads into off-peak periods. The argument for use of this approach here is weaker than usual since departing customers are not likely to confer significant benefits on non-participating customers left behind.

One might also question whether participation is deterred by the existence of large under-recovered FPPAM balances. A customer who selects the Buy-Through Program will likely accelerate payment of their share of these balances into either the first bill or the first 36 months of service. This risk appears to be overstated, though, other than the possibility that some degree of cash liquidity would be necessary for the advance in payment timing. The overall payment level to be made by the customer would be unlikely to change. Accordingly, this possible change in payment timing does not appear to be a barrier to participation.

More generally, the Buy-Through Charge, aside from the administrative component, consists of non-bypassable costs that the customer would pay regardless of participation. The size of the charge might appear to be a deterrent, but clear description of its role would ensure that the customer's perception of additional cost is confined to the cost of program administration: $0.51 per kW-month.

Another cost avoidance issue is whether it is appropriate to use embedded or marginal cost as the basis for avoidance of generation costs. SRP is planning to use embedded costs (i.e., the customer does not pay for generation services under their current tariff). Theoretically, the customer (and their GSP) could claim that the customer departing from standard service should pay their full standard tariff and then be provided with an avoided cost-based discount, where the costs avoided are estimated based on SRP's marginal generation costs. Furthermore, this discount on full service would cause SRP revenue to decline at exactly the same rate as its costs, assuming its avoided cost is equal to the market price. This approach would arguably avoid swings in participation resulting from swings in marginal cost.

However, the question of the valuation of avoided costs is likely to be problematic for two reasons related to price: the challenge of developing an agreed method of estimating avoided cost of generation and the problem of variation over time in the forecasted wholesale price proxy for marginal/avoided cost. Customers applying at different times would receive different credits based on the most recent year-ahead forecast of load-weighted marginal cost. An indication of the practical challenge can be seen below in Section 6 in the review of the problems California and Nevada faced in evaluating avoided cost.

Another challenge with the avoided cost approach is the need for a fixed contract quantity as the basis for valuation. The computational and administrative aspects of this challenge are a good reason for using SRP's embedded cost-based approach: the customer simply is not charged for generation services avoided.

In SRP's case, an additional problem exists: a wholesale price of sufficient granularity and firmness might not be available. The same issues that affect the selection of resupply pricing apply here. Errors in forecasting would produce varying shortfalls and surpluses in cost that would shift to the standard tariff customers of the utility. In summary, the use of avoided cost valuation might avoid swings in participation but would present administrative costs and the possibility of variable cost impacts on remaining customers. Because SRP's embedded generation costs are properly unbundled and are likely to be close to avoided cost on average in the long run, the proposed use of embedded cost appears to be a good starting point for rate design. The simplicity and stability of the pricing plan appears to be advantageous, although it may influence likelihood in participation over time.

A more extensive revision in rate design in the future might also be helpful to stabilize participation. Currently, generation and FPPAM charges recover costs that include fixed costs. Were those to be separated from variable costs, and fixed cost recovery included in the charges to be retained, then the charges to be bypassed could be converted to marginal costs. Essentially, this revision would convert rates E-65 and E-67 into delivery and GSP components, with SRP's GSP service being available to customers who can choose other GSPs. The costs bypassed would then correspond to the utility's marginal costs and non-participating customers would not be at risk of cost shifting.

5.7 Responsibilities of Contracting Parties

SRP's program documents clearly delineate the responsibilities of participating customers, the GSPs, and SRP itself. The eligibility of the GSPs and the nature of their contracting and report activities are defined, including operational interactions with customers and with SRP with regard to scheduling and delivery of power, and in facilitating billing, without formal restrictions being placed on the nature of their contracts with customers. The sole requirement restricting their actions appears to be that account aggregation is out of bounds, at least for project initiation.

Similarly, customers' responsibilities are well defined, with one key component, imbalance settlement with SRP standing out. It appears that SRP has thought through the incentives properties of scheduling and set up a settlement protocol that deters customers from strategic scheduling.

SRP has structured the program to meet its objectives without placing obstacles in participants' and GSPs' paths for contracting and operation of the process of purchasing generation. For the most part, the utility has created a program that facilitates competitive provision of generation services. One remaining issue is the provision of ancillary services, which SRP plans to offer exclusively. In recent testimony at APS, questions arose regarding separate acquisition of ancillary services, but the absence of wholesale markets for these services at present tilts the balance in favor of SRP's approach, at least for the present. This issue can be revisited if market conditions change in the future.

6. COMPARISON WITH OTHER DESIGNS

This section contrasts SRP's Buy-Through Program design with limited retail choice offerings in other jurisdictions including direct access programs in Arizona, California, and Nevada. We also discuss some relevant green tariff power purchase programs in the U.S. These comparisons show that Management's Buy-Through Program design has reasonable program requirements, including the eligible customers and the cap on the size of the program. These comparisons also suggest alternative ways to handle some of the issues with the Buy-Through Program charges raised above.

6.1 Limited Retail Choice in Other Jurisdictions

The National Renewable Energy Laboratory (NREL) summarizes U.S. jurisdictions with full and partial retail energy choice as of 2017 in its report "Charting the Emergence of Corporate Procurement of Utility Scale PV."[37] Retail choice programs enable customers to acquire generation from alternative sources to their utility while continuing to pay for energy distribution costs. While 13 states (e.g., Texas, New York) and Washington D.C. have full retail choice available to all customers, eight states in jurisdictions that have not transitioned to fully de-regulated markets offer limited retail choice, which NREL calls "partial retail choice". The partial retail choice states summarized in the NREL report are California, Georgia, Michigan, Montana, Nevada, Oregon, Virginia, and Washington. Because these states do not have fully deregulated markets, these retail choice offerings are generally limited to certain customers and are subject to enrollment caps. We discuss the California and Nevada Direct Access programs in the following sections.

<u>Eligible Customers</u>

While California and Michigan allow any customer to participate in their retail choice programs, most states limit retail choice programs to large, nonresidential customers.[38] The minimum demand for these large customer-only programs ranges from 900 kW to 5 MW, which puts SRP's 5 MW requirement squarely within the requirements for these programs. Virginia allows two or more customers to aggregate their loads to meet the minimum requirement. Washington determines a customer's retail choice eligibility on a case-by-case basis. Georgia allows only new customers to apply for retail choice at service initiation, prohibiting existing retail service customers from leaving retail service.

<u>Program Limitations and Requirements</u>

Most partial retail choice programs involve program caps to control the impact of the program to the grid. In some cases, these caps are specified as a share of total system loads, such as 10% in Michigan or 12% in California. The large utilities in Oregon have fixed caps of 175 MW (PacifiCorp) and 300 MW (Portland General Electric). This suggests that SRP's Buy-Through Program cap is reasonable.

In states that have renewable portfolio standards, departing customers may be required to meet these standards with their purchased energy, similar to the requirements that utilities must meet in the state. This is the case with Nevada's retail choice program.

<u>Exit Fees</u>

In California, Nevada, and Washington, customers that are departing from a utility's retail service pay an exit fee to the utility to cover the costs of investments made to serve the departing

[37] NREL Technical report: NREL/TP-6A20-69080, September 2017. This report discussed options that corporate customers have for acquiring solar power, including both physical and financial power purchase agreements (PPAs), utility partnerships (including green tariffs and bilateral contracts with utilities), retail choice, and becoming a wholesale power provider.

[38] See Table 3 of the NREL report for details about these programs.

customer's load.[39] We discuss the California and Nevada fees in more detail in the following sections. Virginia does not require an exit fee but requires that customers give utilities five years' notice before exiting retail service.

Program Charges and Retail Rate Bypass

Retail choice programs require that customers continue paying utilities for transmission and delivery-related costs but bypass the generation-related charges. Customers are usually charged for program administration costs and additional fees may be added to account for system planning.

6.2 California Direct Access and Community Choice Aggregation

California requires customers that leave a utility to be served by another provider (i.e., via direct access or to be served by a community choice aggregator) should not shift costs to customers remaining with the utility. That is, departing customers continue to be responsible for costs the utility incurred to serve them. In practice, this requirement is implemented through the Power Cost Indifference Adjustment (PCIA).

Theory of the PCIA

The objective of the PCIA is to recover the difference between the market value and the cost of the energy resources that were contracted on the departing customer's behalf.

The PCIA is described in more detail in the CPUC's most recent annual report on the calculations of the market price benchmarks (MPBs) for the PCIA. [40]

> "The PCIA, or an IOU's Indifference Amount, is equivalent to an IOU's total PCIA eligible portfolio costs less the portfolio's market value in a given year. Market value is defined in D.19-10-001 as "the estimated financial value, measured in dollars, that is attributed to an IOU portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year." D.19-10-001 defines MPBs as "estimates of the value per unit (not total portfolio value) associated with three principal sources of value in IOU portfolios (energy, resource adequacy, and renewable energy)." MPBs are multiplied by the relevant portfolio volume as part of the overall calculation of market value. The forecasted adders are mechanisms that aim to reduce uncertainty of the indifference amount, and the true up adders are mechanisms that aim to align realized market revenues with forecasted values."

The PCIA is calculated for different customer exit years (the "vintage") to account for the fact that the composition of energy resources changes over time. The PCIA will tend to go down over time, eventually reaching zero when enough time has passed that the relevant resources are retired, and contracts have expired.

[39] Fees associated with leaving retail service can be a combination of upfront exit fees, ongoing adjustment fees, and other surcharges to prevent cost-shifting.
[40] https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/community-choice-aggregation-and-direct-access/calculation-of-the-market-price-benchmarks-20220930.pdf.

CCAs have some objections to the PCIA, including non-transparency of the calculations; lack of incentives for utilities to reduce costs; the added rate volatility; and questions about its effectiveness in preventing cost shifts.[41]

Components of the PCIA

Energy Index

The Energy Index represents the market value of the contracted power in $/MWh. It is calculated using Platts-ICE Forward-Curve Electricity Market Data. It was formerly called the "Brown Power Index".

Resource Adequacy (RA) Adder

The RA adder is the value of each unit of capacity in the PCIA-eligible portfolio used to satisfy RA obligations, expressed in $/kW-month. It has three sub-components: system, local, and flexible. It is calculated from RA-only market transactions data.

Renewable Portfolio Standard (RPS) Adder

The RPS adder reflects the value (in $/MWh) of energy that helps meet RPS obligations. It is developed from market transactions data.

Comparison of the PCIA and Management's Proposal

The PCIA is intended to address many of the same issues as management's proposal but uses different methods.

- *More comprehensive view of generation value.* The PCIA compares the market value to the cost of the entire applicable generation portfolio, whereas management's Early Technology Adoption Charge (ETAC) proposal is limited to renewable sources built prior to 2013. The implicit assumption of management's proposal is that the generation that served departing customers was either purchased at market prices or has a value that approximates that of the market. The advantage of this assumption is that it simplifies the calculations, which may improve transparency and stakeholder acceptance.
- *Vintaging of the generation assets.* The PCIA has different values according to the year in which the customer left the system. (The PCIA for a given vintage also changes over time.) At this time, vintaging isn't necessary for SRP, as it is calculating the ETAC for the first year of the program. In addition, calculating the ETAC for only older renewable assets may limit (or perhaps eliminate) the need for vintaging going forward. However, SRP may want to revisit this issue if additional resources become uneconomic in the future.
- *The FPPAM Settlement Adjustment (FSA).* While the PCIA does not include shares of the fuel adjustment clause, the principle behind the PCIA supports management's proposal to charge the FSA to departing customers. The Public Utility Code sections cited by the CPUC (366.1 and 366.2) specifically reference

[41] https://californiachoiceenergyauthority.com/pcia-fee/.

recovering the departing customer's "fair share" of purchase power costs. We therefore view California as providing support for management's FSA proposal.

- *Basis for the renewable energy value.* SRP management is proposing to base the renewable value of the ETAC-eligible resources on its Solar Choice Plus Program premium, which is currently $0.005 per kWh. In contrast, California bases its renewable value on RPS-related market transactions.

6.3 MGM Departure from Nevada Power

In 2015, MGM Resorts International (MGM) filed an application with the Public Utilities Commission of Nevada to exit NV Energy's system and instead purchase energy, capacity, and/or ancillary services from a third-party provider. The departure occurred in October 2016, with MGM paying an initial exit fee (called an "impact fee" in the proceeding) of $86.9 million. MGM continued to pay impact fees of varying amounts for the following six years, at which time MGM's departure was found to no longer burden remaining customers.

The December 3, 2015 Order approving MGM's application[42] noted that MGM would "pay its load ratio share of unrecovered adjusted balances in Nevada Power's deferred accounts, as reasonably determined by the Commission." (Order page 7, paragraph 18.) This establishes a principle that is consistent with SRP management's FPPAM Settlement Adjustment proposal, which charges departing customers their share (based on their usage divided by system sales) if FPPAM balances, provided the FPPAM balance is outside a $20 million dead-band.

In addition to the impact fee, MGM was required to pay a set of non-bypassable charges. One of these charges is the Renewable Base Tariff Energy Rate (R-BTER) charge, which represents "the embedded costs associated with the long term, above-market-price (or out-of-the-money), must-take renewable energy resource contracts that affect the BTER." (Order page 66, paragraph 189.) This is consistent with SRP management's proposed ETAC, which is intended to recover costs associated with above-market renewable energy sources constructed prior to 2013.

As was the case with California's PCIA, Nevada took a more comprehensive approach than SRP is proposing to evaluate the generation costs that could be shifted to non-participants. For example, NV Energy was directed to perform production cost simulations using PROMOD for various scenarios, the results of which determined the BTER costs that needed to be recovered from MGM to prevent a cost shift. The more comprehensive approach has the potential to better identify potential cost shifts but requires assumptions and is complex to implement. These features may reduce stakeholder acceptance.

Following the MGM proceeding, NV Energy expressed dissatisfaction with the impact-fee methodology's ability to prevent cost shifts as more customers left their system in the same manner as MGM. The Staff-directed modeling used to calculate the impact fees assumed that load growth would eventually employ the generation resources formerly used to serve the departing customer. However, as more customers have left NV Energy's system, the load growth

[42] https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-5/7908.pdf.

forecasts have not come to pass. This has caused NV Energy to propose increasing the six-year exit fee period to 18 years.[43]

6.4 Arizona Public Service's AG-X Rate

Arizona Public Service Company (APS), the other major utility in the Phoenix metropolitan area, has a long-standing buy-through program that is set out in its rate rider AG-X. APS proposed revisions to its AG-X rate rider in a 2022 rate case.[44] We compare the current terms of the AG-X rate rider to SRP's Buy-Through Program and discuss APS' proposed revisions from the 2022 rate case.[45]

Eligible Customers

The AG-X rate rider is available to customers served on the E-34, E-35, E32-L, or E-32 TOU L retail rates who have an aggregated peak load of 10 MW.[46] While this minimum peak load requirement is higher than the 5 MW minimum in SRP's Buy-Through Program, APS has requested to lower this requirement to 5 MW in its 2022 rate case. APS allows customers participating in the program to have load growth of up to 10% and does not limit its program to high load factor customers. APS also has a more expansive set of non-residential customers who are eligible for the AG-X rate rider. The eligible rates include customers that are metered at transmission, primary, or secondary including self-contained meters and instrument-rated meters. The fact that APS allows for account aggregation makes lower voltage service compatible with the minimum size requirements.

Program Limitations and Requirements

The AG-X rate rider is limited to 200 MW of demand and half of the program is reserved for the largest, high load factor customers, those with demands of at least 20 MW and a load factor of at least 70%. APS uses a lottery system to admit customers to the program when demand for the program exceeds the program cap. The terms and conditions for participating customers and GSPs are similar to SRP's Buy-Through Program requirements described above.

While APS does have a minimum demand requirement for participating customers, it does not specify a cap for customer participation size like SRP's 50 MW cap. As such, there are no provisions for partial customer participation as in SRP's Buy-Through Program.

[43] https://thenevadaindependent.com/article/nv-energy-calls-for-higher-exit-fees-on-growing-list-of-departing-companies.
[44] See Arizona Corporation Commission Docket No. E-01345A-22-0144.
[45] For current AG-X terms, see APS' Rate Rider AG-X, Generation Service, Alternative Generation, effective December 1, 2021, https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Business/Rate-Riders/agxAlternativeGenerationGeneralServiceExperimental.ashx?la=en.
[46] Aggregated load refers to the total load of the customer's separately metered accounts, which may include metered accounts served on the E-32 M, E-32 TOU M, E-32 S, or E-32 TOU S retail rates if these are on the same premise as the eligible rate schedule accounts. Aggregated customers must have the same corporate name, ownership, and identity but can be operating under multiple trade names. In is 2022 rate case, APS proposed allowing E-32 M and E-32 TOU M customers to be eligible for the AG-X program.

Buy-Through Charges and Retail Rate Bypass

Customers on rate rider AG-X do not pay retail generation tariffs, power supply adjustment charges, environmental improvement surcharges, and associated taxes. The AG-X rate rider specifies a separate administrative fee for the program bases on monthly energy use of $0.00171 per kWh, and a monthly reserve capacity demand charge of $5.248 per kW.[47] The AG-X rate rider does not charge customers for any portion of APS' investments to meet its obligations for environmental improvement projects.

In its 2022 rate case, APS proposed to modify the AG-X program, providing customers with two enrollment options. Customers may find a GSP that will provide resource adequacy for their loads, including a 15% reserve margin. This option requires that GSPs can prove that the energy being sourced is a more reliable and not otherwise committed to resource adequacy or balancing, according to APS' own standards for its resource adequacy. Customers that choose this option will avoid the reserve capacity charge on the AG-X rate rider but must give three year's notice to return to retail service. Customers that elect to have APS provide resource adequacy will have less scrutiny of their power sourcing but will continue to pay the reserve capacity charge and must give one year's notice to return to retail service. It is worth noting that APS proposed changing this reserve capacity charge to be equal to the unbundled demand generation charge from the E-34 tariff, which would be more than double the previous rate. Essentially these customers would only bypass the generation energy charges and the PSA charge.

In contrast, SRP's buy-through design provides customers with resource adequacy, charges them a more modest reserve capacity fee of $2.87 per kW, and requires three year's notice to return to retail service.

Imbalance Charges

APS has a process for settlement of imbalances similar to the process laid out in SRP's Buy-Through Program with imbalance charges that are based on APS's OATT Schedule 4 imbalance charges (i.e., the relevant LAP price). APS also has a two-tiered system for imbalance charges, with the same threshold between tiers 1 and 2 of +/- 15% or 2 MW. The premium for tier 2 imbalances is a set amount of $3/MWh rather than a +/- 25% premium. APS defines excess imbalances as months with more than 20% of the hours having at least a 20% imbalance, a slightly more lenient definition of excess imbalance compared to SRP's Buy-Through Program. Similarly, customers with two or more months of excess imbalance may be terminated from the program.

Resupply Energy

Customers that are between GSPs or that give less than one year's notice to leave the AG-X program are charged for energy according to the resupply price, which is the same index used as SRP (i.e., the Palo Verde Peak or Off-Peak ICE Day-Ahead Power prices). APS also adds a $10/MWh fee to the index price, similar to SRP. APS specifies that the resupply price cannot be less than $0 and reserves the right to charge the customer based on the applicable retail rate.

[47] In its 2022 rate case, APS proposed lowering the administrative fee to $0.00164 per kWh and changing the capacity reserve charge to be the unbundled generation demand charge associated with the E-34 rate schedule, which is proposed to be set at $12.429 per kW.

Fuel Charge Settlement

APS does not have any provision for the settlement of power supply adjustment charges or other charges such as SRP's ETAC fee that customers will bypass on the AG-X rate rider.

6.5 Green Power Purchase Programs

Green power purchase programs enable customers to procure renewable energy outside of their utility's standard offerings in order to acquire the associated renewable energy certificates (RECs) to satisfy corporate sustainability goals. Green power purchase programs are good comparisons to SRP's Buy-Through Program because many are offered in similarly regulated jurisdictions. We find that many of these programs have eligibility requirements and program limitations that are comparable to SRP's program design. Moreover, some programs provide examples of alternatives to SRP's design for handling issues of rate bypass and program charges.

The Clean Energy Buyers Association (CEBA) produces a periodic summary of green tariffs in the U.S.[48] According to CEBA, "Green tariffs are voluntary utility programs that allow eligible customers to buy both the energy and associated renewable energy certificates (RECs) from a large-scale renewable energy project through an independent tariff or as a rider on a customer's current electricity bill."[49] CEBA categorizes green tariff programs into sleeved PPA models in which customers can enter into physical PPAs with renewable generators, subscription programs in which customers can subscribe to large renewable energy generation projects that are owned by the utility or for which the utility has a PPA, and market-based rate programs which enable wholesale market participation opportunities for customers or groups of customers. Sleeved PPA models are the relevant comparison, and we discuss the program designs that are presented in the CEBA reports.

Sleeved PPA programs are available through Alliant Energy (Wisconsin), Dominion Energy (Virginia), Duke Energy Carolinas, East Kentucky Power Cooperative, Idaho Power, Indiana Michigan Power, Kentucky Power, Kentucky Utilities Company (Kentucky and Virginia), Louisville Gas and Electric Company/Kentucky Utilities Company, Madison Gas & Electric (Wisconsin), Public Service Company of New Mexico, NV Energy, Portland General Electric (Oregon), Rocky Mountain Power (Utah), Tennessee Valley Authority, WE Energies (Wisconsin), and Black Hills Energy (Wyoming).[50] We discuss some of the relevant program elements, but do not provide a comprehensive summary of all of these programs.

Eligible Customers

Most utilities limit green power purchase programs to nonresidential customers, and in most cases the programs are limited to large customers on specific retail tariffs or on specific meter sizes.[51] The minimum demand for these programs ranges from 1 MW to 10 MW, consistent with

[48] CEBA, "U.S. Electricity Markets: Utility Green Tariff Update," December 2020, and CEBA, "U.S. Utility Green Tariff Report," January 2023. Both reports are available at https://cebuyers.org/programs/education-engagement/green-tariffs/.

[49] CEBA, "U.S. Utility Green Tariff Report," January 2023, pg. 5.

[50] This is based on the sleeved PPA programs summarized in the 2020 and 2023 CEBA reports.

[51] See the CEBA 2020 and 2023 reports for the specific customer classes and rate schedules that are eligible for each utility.

SRP's 5 MW requirement. Unlike SRP, most of these programs allow customers to aggregate multiple service accounts to meet the minimum requirements, often across the utility's system. Black Hills Energy's program is designed for new customer loads that are expected to be 13 MW or greater and is not open to existing customers.[52] Most utilities do not have load factor requirements for customers, but Public Service Company of New Mexico is an exception with their 75% minimum load factor requirement.

Some programs allow customers to subscribe to capacity that exceeds their historical peak demands.[53] Black Hills Energy, on the other hand, only allows up to 85% of billing capacity in order to include a planning reserve margin. Many of the utilities also allow net metering customers to join the program.

Program Limitations and Requirements

Most of these programs have subscription caps ranging from just 50 MW for Madison Gas and Electric's existing customers (no limit for new customers) to 4,000 MW for Duke Energy in North Carolina. More commonly the cap is around 150-300 MW, consistent with SRP's Buy-Through Program cap. Other utilities such as the Tennessee Valley Authority do not have enrollment caps, but enrollment may be subject to the regulator's approval in these cases. Utilities such as Duke Energy Carolinas have sub-divided the program cap to reserve a portion of the program for specific customer groups such as local governments and higher education institutions.

Several of the utilities require that the renewable generation facility is located in their service territory or the same state. Kentucky Utilities Company specifies that the generator must be located in one of the states in the same region including Kentucky, Indiana, Tennessee, Ohio, West Virginia, Virginia, Missouri, or Illinois. Other utilities require that the generator be located within the RTO territory (e.g., PJM's territory).

It is also common for these programs to require a minimum commitment by the customer which can range from as little as one year for Indiana Michigan Power to 15 or more years but is more commonly around five years. This is usually related to whether the utility commissions new renewable projects on the customer's behalf rather than just contracting with an existing renewable generator. In these cases, there can also be project size limitations such as 2-500 MW projects within the Tennessee Valley Authority. Idaho Power also works with customers to develop new renewable generation facilities with the construction cost borne by the customer, while Rocky Mountain Power assumes ownership of facilities that are built by developers. Other utilities such as Indiana and Michigan Power work with customers to find renewable generation sources and to execute a PPA for this energy supply. Duke Energy Carolinas allows customers to find their own renewable generators.

Program Charges and Retail Rate Bypass

Most green tariff (sleeve PPA) programs have a similar rate structure which involves the customers continuing to pay their retail tariffs, the additional cost of the acquired renewable energy, and a modest administrative fee (usually between several hundred and several thousand dollars per month). In exchange, customers are given a credit for the renewable energy they

[52] Public Service Company of New Mexico also limits its green tariff program to new customers.

[53] For example, Duke Energy Carolinas has allowed customers to purchase up to 125% of their capacity needs and Idaho Power allows up to 110%. This provision is less relevant to buy-through programs.

consume. This approach assures that customers in green tariff programs are paying all of their system costs and are not cross subsidized by other customers. The nature of the energy credit varies widely across these programs:

- Duke Energy Carolinas credits customers for the renewable energy delivered by the GSP to the system based on the marginal hourly avoided cost to Duke. These marginal avoided costs include expected production costs as well as capacity costs for hours in which there are generation constraints.
- East Kentucky Power Cooperative credits participants based on the total avoided cost (i.e., the base fuel, the fuel adjustment clause, and the variable environmental surcharge)/MWh and a capacity credit, when applicable. The credit is the lesser of the total credit or the PJM Locational Marginal Price.
- Portland General Electric gives participants a credit for the energy and capacity value of the renewable power produced. The utility also charges customers a risk adjustment factor if customers do not commit to the program for the full PPA term.
- Alliant Energy allows customers to bypass fuel cost surcharges on renewable energy consumed and gives customers renewable energy credits based on the MISO energy market prices.
- Dominion Energy provides credits based on PJM settlement amounts.
- Public Service Company of New Mexico gives participants excess energy credits based on the Palo Verde ICE day-ahead price index during hours with energy production that exceeds customer demand.
- WE Energies gives customers a monthly energy generation credit equal to the renewable generation project's settled MISO market energy credit value (applied to the lesser of energy generation or actual consumption) and a monthly capacity credit equal to 1/12 of the resource's annual amount capacity credit from MISO.
- Madison Gas and Electric participants bypass fuel costs and renewable resource rates (instead participants pay a project-specific renewable resource rate) but do not get credits for renewable energy production.
- Black Hills bypass the Power Cost Adjustment and DSM surcharges but are assessed an additional microgrid management fee based on billing capacity of the facility as well as facility-specific energy costs.
- Idaho Power has a negotiated price that the customers pay for renewable generation project output and the customer gets credited this price for energy production in excess of their demand.
- Kentucky Utilities Company gives participants renewable energy credits that are negotiated with the customers in addition to the negotiated project charges.

Rocky Mountain Power is an exception to this general structure of paying full retail rates and getting renewables credits. The utility has a completely separate tariff for customers in this program that includes customer and delivery charges and demand charges based on the project contract capacity. Customers are not credited for renewable energy production in excess of the customer's demand.

7. FINDINGS

SRP's management team has developed a proposed Buy-Through Program that meets all the design criteria identified by the Board regarding the costing, pricing, and statutory requirements for a successful program. Most importantly, the program structure promotes full cost recovery from participants while offering them the opportunity to seek and acquire efficiently priced generation services.

The cost underpinnings of the buy-through design are sound.

- Embedded costs of delivery services are properly classified by cost-causative factor and appear to be allocated according to conventional principles.
- Generation services, where provided by SRP (imbalance and resupply) are based on sensible representations of marginal cost/wholesale market energy price.
- Ancillary services are acceptable in embedded cost form given the lack of reserves markets in the region.

Management's design offers pricing that recovers cost fully and is efficient.

- The design is consistent with the Board's general principles of gradualism, price efficiency, and revenue recovery.
- The design is consistent with sound utility practice and general economic theory:
  - Delivery services are priced based on embedded costs based on established costing methods. In particular, fixed cost recovery does not appear to take place via volumetric (kWh) pricing.
  - Generation services are based on market prices.
- Prices reflect their underlying cost drivers, by subfunction.

Lastly, the program's structure responds fully to the obligations of the legislation.

Management's approach to the key issues of buy-through pricing is largely sound, although we raise questions as to pricing methodology and eligibility/departure requirements.

- **Resource adequacy.** SRP's program provisions limiting scale, requiring detailed GSP vetting, tiered pricing of imbalances and resupply premium pricing all indicate that the program has multiple structures to support SRP being able to deliver generation to all its customers.
- **POLR consideration.** SRP plans to use public price indexes that allow the utility to match revenues from POLR customers to the cost to serve them.
- **Imbalance service charges.** SRP has chosen to settle imbalances with customers (rather than the GSP), using a tiered structure based on the utility's expectation that this will avoid or limit strategic scheduling based on forecasts of market prices relative to contract prices.
  - There might be opposition to the tiered pricing approach, but it appears to provide SRP with a necessary incentive to customers to minimize imbalances. The power to remove someone from the rate for persistent excessive imbalances is reasonable but arguably not sufficient.

- The Tier 2 markup might be set at a level that makes SRP indifferent between customer imbalance increases and reductions. Observation of behavior early in the program may provide guidance here.

- **GSP Default.** SRP's use of the Palo Verde day-ahead price indexes plus a price premium appears to give customers using resupply service a strong incentive to recontract with a new GSP. The resupply price also gives customers the incentive to give SRP three-years' notice before returning to retail service.
  - There might be opposition to SRP charging a premium for resupply service. However, SRP is entitled to earn a premium in return for offering the service.
  - SRP's preference for Palo Verde appears defensible from both theoretical and operational perspectives.
- **Return to Standard Offerings.** SRP offers a clear path to return. The issue associated with return is the length of advance notice. Three years' notice is based on capacity availability concerns and planning experience. However, this may be conservative, and a policy of allowing a shorter time period in the event of availability may help to improve the attractiveness of the program.
- **Bypass.** The Buy-Through Charge is well documented and the calculations of administrative, reserve capacity and ETAC charges appear sound and defensible. As the program ages, reductions in administrative and ETAC charges should be expected.
- **Responsibilities of Contracting Parties.** SRP's program documents set out parties' responsibilities clearly. Aggregation is not currently feasible but can be considered in the future.
  - Ancillary services will be managed by SRP for sound reasons of lack of market sources. As markets develop, this could change without hurting the program.

Management's design appears to conform to industry practice based on a short list of examples.

- Examples from California and Nevada indicate that there is precedent for SRP's approach to limiting cost shifting.
  - California devised the Power Cost Indifference Adjustment (PCIA) to ensure that the out-of-market costs of energy resources would continue to be billed to customers who secured power elsewhere. Their methodology does not need to be applied at SRP partly due to the relatively small scale of SRP's cost recovery and partly due to their more comprehensive view of generation value.
  - Nevada developed an impact-fee approach to valuation. Again, it has value as precedent for recovering out-of-market costs, but its methodology appears to be more complex than SRP needs, involving production cost simulations to estimate these costs.
  - FPPAM: it is difficult to find analogies but SRP's approach appears to be consistent with what other utilities do regarding fuel and purchased power costs.
  - ETAC: SRP's approach is simpler than the California and Nevada methodologies. SRP's approach has the advantages of transparency and likely ready acceptance. The possible disadvantage is that the approach does not

attempt to evaluate the market value (and hence out-of-market cost) of the whole generation portfolio.

- Several aspects of the SRP design make use of similar design components at Arizona Public Service in its AG-X rate. However, SRP has adopted a different approach in some cases, partly due to differences in underlying rate design and pricing, and partly based on different perceptions about pricing incentives.
    - Both utilities include a reserve capacity charge to ensure that the lost customer loads continue to pay their share of reserve capacity costs, as the host utility is providing that reserve capacity.
    - Both utilities undertake imbalance settlement, but APS settles with the GSPs while SRP has decided to settle with the customers, based on the understanding that customer strategic behavior to minimize their costs can be influenced and reduced by a tiered pricing scheme.

Summary:

SRP management's proposed Buy-Through Program appears to meet the Board's requirements for a successful design: participating customers can contract with GSPs for service without introducing cost shifts to other customers, paying embedded costs for delivery services and market-based prices for generation services from their GSPs and from SRP through imbalance settlement and resupply pricing in the event of contract default. Customers may return to SRP under clear terms. Furthermore, the program appears capable of being scaled up and of responding to changes in wholesale markets, including with respect to alternatives to the provision of ancillary services.

APPENDIX: COMPARISON OF HISTORICAL ICE DAY-AHEAD PEAK PRICES AND CAISO REAL-TIME PEAK PRICES, PALO VERDE NODE

This appendix examines the Palo Verde ICE day-ahead peak weighted average prices (available through the Energy Information Administration) compared to the CAISO real-time energy imbalance market (EIM) hourly LAP prices for the Palo Verde node (PALO_VRDE_5_N101) provided by SRP Management, for the period from 2020 through 2022. The ICE peak period hours are those ending 7 through 22 (i.e., 6:00 am to 10:00 pm) Monday through Saturday.

ICE Day-Ahead Price Premium over Real-Time Market

We compared the Palo Verde ICE peak day-ahead prices to the EIM prices to assess SRP management's belief that the former index reflects the value of firm power (and to some extent capacity constraints) which are not accounted for to the same extent in the EIM prices. The table below summarizes the average hourly prices during ICE peak hours compared to the EIM prices for the Palo Verde (PV) node during the same hours, by year. There is over a 50% premium in the ICE peak prices compared to the EIM prices during this time, which may be due in part to historically high prices and large price volatility during this time.

Table 1
Annual Average Palo Verde Peak Period Prices

Peak Price Comparison	2020	2021	2022
EIM Annual Avg Price	$ 26.87	$ 40.33	$ 63.96
PV ICE Annual Avg Price	$ 44.95	$ 59.62	$ 98.23
PV ICE % Premium	67%	48%	54%

SRP management conducted a similar analysis for all hours (including the Palo Verde ICE off-peak period prices). Their calculations yielded a smaller price premium in each year, which one might expect when including off-peak hours. Nonetheless, this analysis shows that the WSPP Schedule C firm power that is traded on the ICE is reflected in the persistent price premium over the real-time EIM prices.

Table 2
Annual Average Palo Verde All-Hours Prices

All Hours Comparison	2020	2021	2022
EIM Annual Avg Price	$ 24.59	$ 36.80	$ 62.03
PV ICE Annual Avg Price	$ 37.84	$ 51.77	$ 88.57
PV ICE % Premium	54%	41%	43%

Hourly Variation in the ICE Day-Ahead Prices and the Real-Time Market

Next, we examine the hourly differences between the ICE Day-ahead and EIM prices. Figure 1 below shows the average prices across peak days in 2020-2022 in each ICE peak period hour. The Palo Verde ICE day-ahead peak prices (blue) are higher on average than the EIM prices at the Palo Verde node (red) during each hour except for the hour ending 19. This reflects the fact that the ICE day-ahead prices are not shaped and are identical over 16 hours. The figure also shows that there is a considerable price premium during hours ending 7-16 for ICE day-ahead prices relative to EIM prices.

One might question whether variations in resupply customer load might lead to pricing inaccuracy (over- or under-charging of customers) under TOU pricing relative to an hourly pricing scheme. SRP's buy-through customers are expected to have relatively high load factors but loads with differing patterns within TOU periods might have identical bills under the proposed TOU pricing scheme but different bills under an hourly shaped pricing arrangement. CAISO provides hourly shaping factors from the real-time market that would permit creation of shaped hourly Palo Verde prices.

If the Palo Verde ICE peak period were shortened to reflect a time period closer to SRP's own TOU peak period hours, then the problem might be less significant. However, SRP cannot control the TOU period length of the Palo Verde ICE prices.

Figure 1
Average Hourly Palo Verde Peak Period Prices

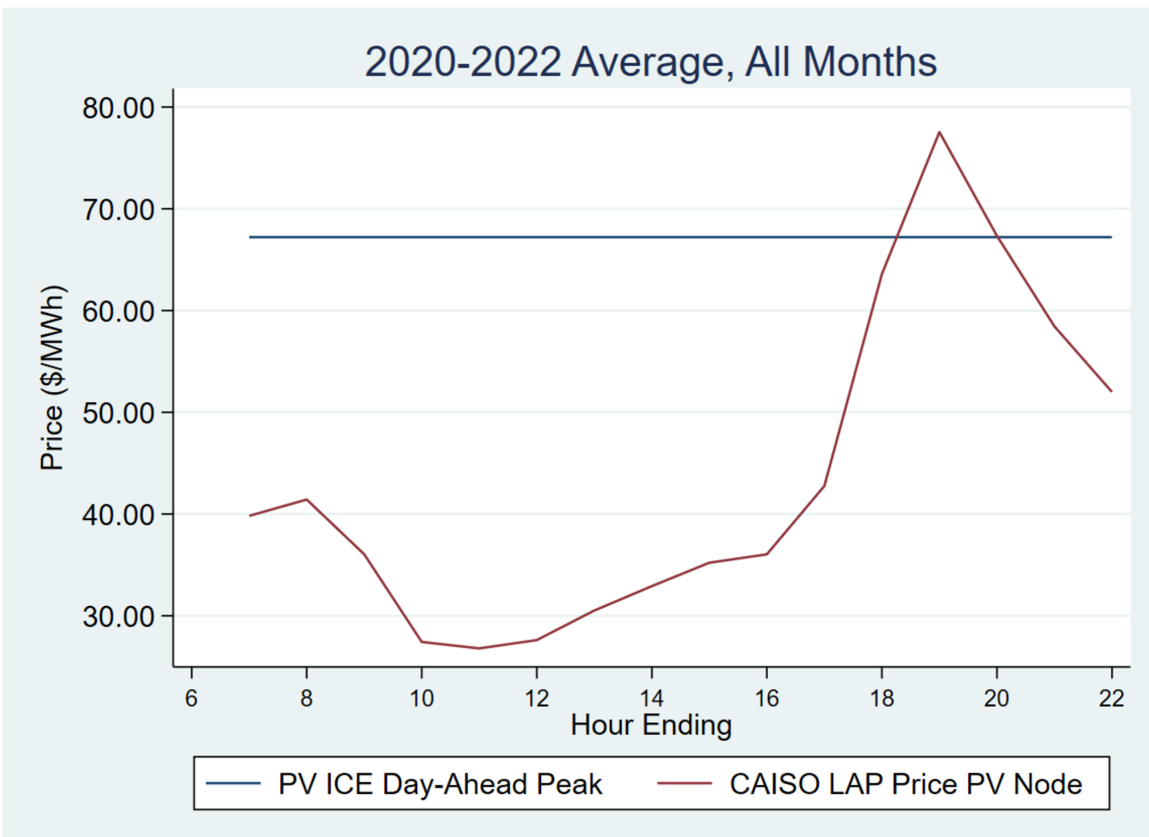
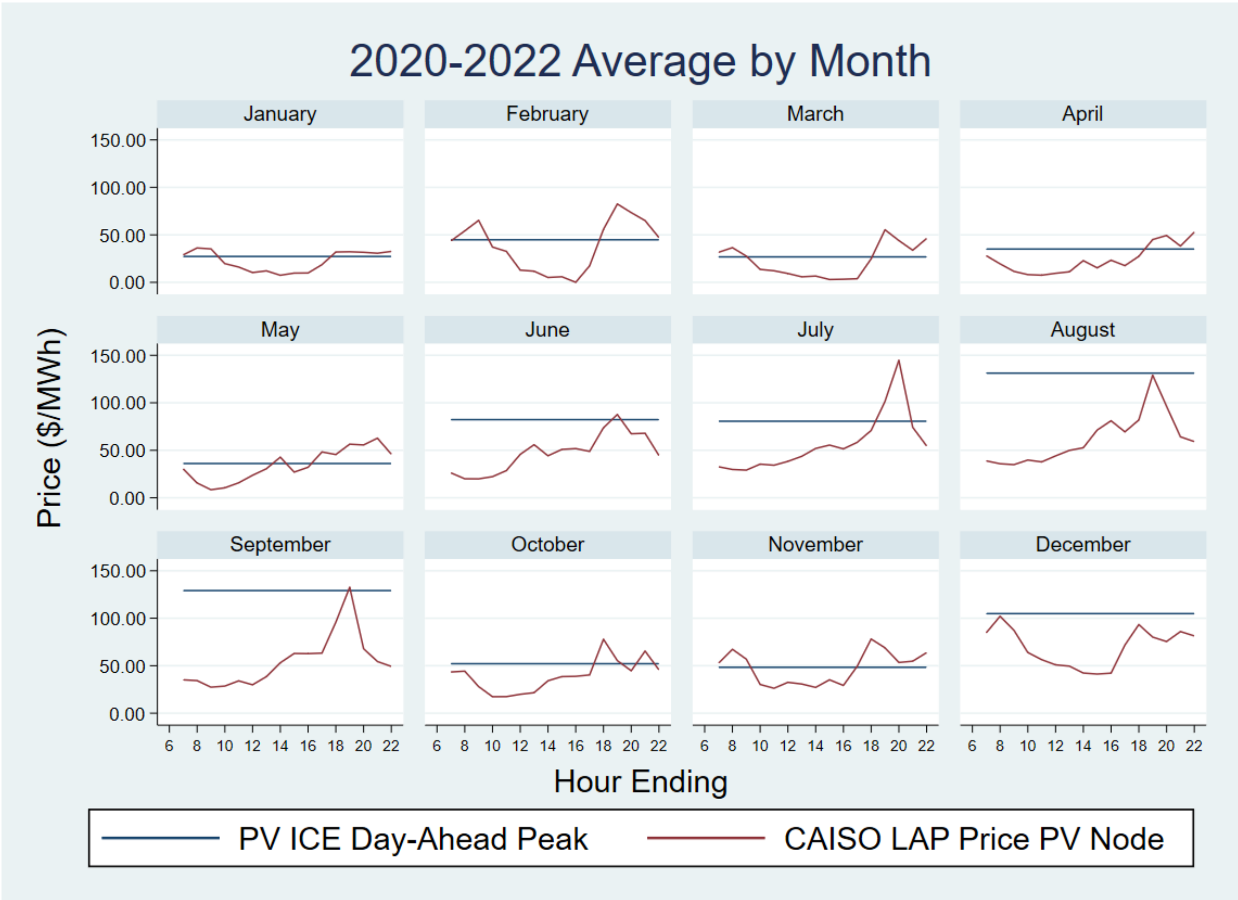


Figure 2 provides a comparison by month of the year. The winter months have a slightly different pattern of price premium hours in both the morning and evening hours compared to the summer months which have a large evening spike in hourly prices.

Figure 2
Average Hourly Palo Verde Peak Period Prices, by Month



Resupply Energy Price Premium Analysis

Figure 3 shows the average prices across peak days in 2020-2022 in each ICE peak period hour. In addition to the average of the ICE day-ahead (blue) and the EIM prices (green), there is a line representing SRP's resupply price (red) over the same period. The price premium indicates, that for these data, the resupply price is higher than the EIM price, even during the peak hour ending 19.

The figure should be interpreted with caution. SRP intends to provide resupply energy at the resupply price and to purchase the required energy and capacity at Palo Verde day-ahead price (the resupply price excluding the premium). Such pricing has low risk to the utility and its standard tariff customers but high variability across days and months, representing risk to the resupply customer while subject to these prices. Additionally, resupply customers with different load profiles might pay the same for resupply energy but have different costs to serve were hourly pricing available. In SRP's case, at least for the present, such pricing is not available with reliability. While CAISO day-ahead hourly prices are available in some months (typically not peak summer months) it would be difficult to characterize such power as firm in the sense that the Palo Verde ICE day-ahead power is.

Figure 3
Average Hourly Palo Verde Peak Period Prices
and SRP Resupply Price

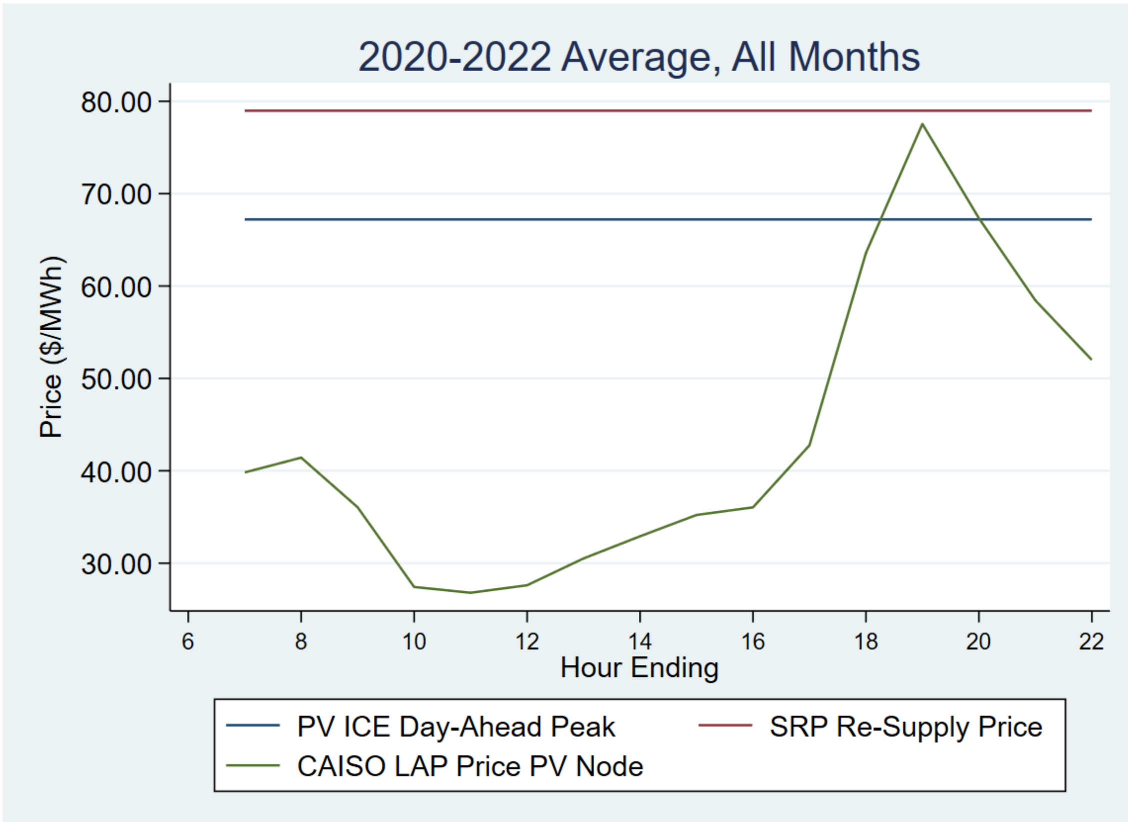
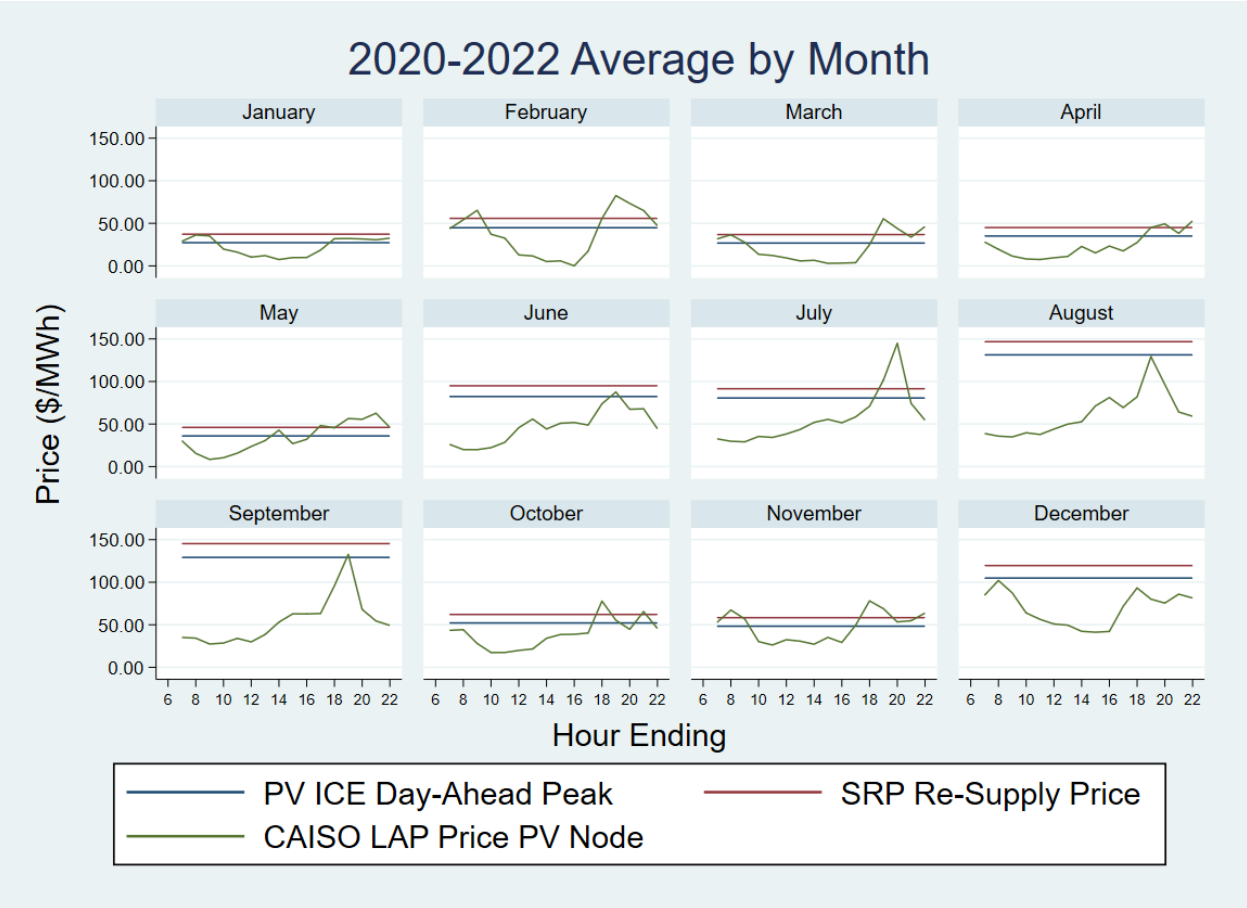


Figure 4 shows a similar comparison by month of the year. Each month is depicted using the same vertical scale, indicating seasonality of pricing for the historical period. The level of the resupply price varies with the season, rising in summer and falling in other months.

Figure 4
Average Hourly Palo Verde Peak Period Prices
and SRP Resupply Price, by Month



Salt River Project: Review of Management's Buy-Through Pricing Proposal

Project Manager: Mr. Bruce Chapman,
Project Team Members:
Mr. Robert Camfield, Mr. Nicholas Crowley,
Dr. Daniel Hansen, Dr. Corey Lott

Scope of Review of Buy-Through Proposal

General Overview:

- Consistency with Board's pricing principles
- Consistency with economic principles and practices
- Reflection of underlying costs
- Compliance with Arizona legislation (A.R.S. § 30-810)

Review of Topics:

- GSP resource adequacy
- POLR capability
- Imbalance service charges
- GSP default
- Return to SRP standard tariffs
- Non-bypassable costs
- Responsibilities of parties

Consistency with Board's Pricing Principles

- Management's proposal is consistent with these principles:
  - *Gradualism:* delivery service rate design and pricing remain unchanged.
    - Bill impacts are restricted to cost impacts of customer choice of GSP.
  - *Cost basis:* delivery service costs are recovered in delivery charges.
    - Cost shifting due to cancellation of energy services is unlikely.
  - *Customer choice:* customer can choose generation service provider without restriction, subject to GSP quality requirements.
  - *Equity:* buy-through and standard customers are treated equally regarding delivery services
  - *Revenue sufficiency:* SRP fully recovers delivery costs, including transmission; also fully recovers generation ancillary services.
    - Deferred costs are recovered by settlement payment/credit.

Consistency with Economic Theory and Industry Practice

- Management's proposal is consistent with principles and practice:
  - Delivery services are natural monopolies; cost basis is embedded; pricing based on fully allocated costs under principles of cost allocation. Standard industry practice.
  - Generation services can be provided under competitive conditions; consistent with "workably competitive" view of generation.
  - Cross subsidization is avoided by unbundled pricing of generation from delivery functions. Clearer unbundling than most traditional industry pricing practice.
  - Departure/return rules protect standard customers: participating customer is responsible for providing capacity via GSP.
  - Imbalance and resupply pricing of generation services is market-based.

Reflection of Underlying Costs

- Delivery charges are unbundled from generation costs.
  - Cost Allocation Study meets industry standards of cost functionalization, classification, allocation.
- Generation charges for imbalance and resupply are based on wholesale market prices/indexes.
  - Effect is to closely approximate SRP’s wholesale energy costs, limiting risk for full-service SRP customers.

Compliance with Arizona Legislation

- Full compliance:
  - Timely
  - Full definition of terms and conditions for participation
  - Clear pricing structure
  - Avoids threats to system reliability:
    - Customer contracts with GSP for reliability.
    - Abandonment/departure require time allowance to ensure capacity.

GSP Resource Adequacy

- Limits on participation
- Scheduling rules
- Price incentive to minimize imbalances
- Maximize likelihood of meeting resupply needs
  - Firm power pricing of resupply
  - Reserve capacity provision of Buy-Through Charge

Provider of Last Resort Considerations

- Arises if a GSP defaults.
- Terms of use are comprehensive.
- Resupply price is transparent, publicly available.
- Price variability provides inducement to customer to secure new GSP (or return to SRP).

Imbalance Service Charges

- Requiring settlement with customer (not GSP) and Tier 2 pricing reduces likelihood of strategic over/under-scheduling.
- Tier 2 pricing (premium/discount for large imbalances) provides inducement to minimize imbalances and controls costs of settlement for SRP.
- Load Aggregation Point (LAP) pricing is transparent.
- Use of LAP pricing is appropriate for small-scale ongoing compensation for imbalances.
- Termination of access to Buy-Through Program is appropriate for control of risk to SRP of persistent excessive balances (20% of hours with Tier 2 imbalances, for two months in a year).

GSP Default and Resupply Energy

- GSP default creates short-notice need for capacity to serve the buy-through customer.
  - SRP does not have the obligation to have capacity available.
  - SRP and its standard tariff customers appear adequately protected by notice provision and resupply price provisions.
- Resupply pricing covers customers' full load for an uncertain period of time; different service from Imbalance, which is ongoing and for small amounts of usage.
- Resupply price is transparent, publicly available, with premium on index values provided by Palo Verde hub.
- Price variability provides an incentive to recontract.
- Three-year requirement for customer to return to SRP is designed to allow SRP to ensure capacity to serve.
  - SRP could offer 1) to allow return if capacity becomes available; 2) non-firm power in the interim.

Non-Bypassable Costs

- SRP buy-through design offers full recovery:
  - Unbundling of delivery and generation services pricing.
  - Buy-Through Charge recovers program administration, reserve capacity, and early renewables generation costs that are now out-of-market
  - FPPAM balances are set out for both departing and returning customers.
  - Imbalance and resupply prices appear capable of covering SRP costs by matching market prices; incentives appear appropriate for minimizing risk.
- Buy-Through Charge updating:
  - Administrative cost covers first five years of program, including setup; assuming full subscription, cost should be reduced to ongoing administrative costs only.
  - ETAC charges should be updated periodically as well. Expect reduction over time.
- FPPAM settlement likely to be updated to reflect changing balance.

Non-Bypassable Costs (2)

- Generation back-out valued at SRP's embedded cost (generation energy and capacity, and FPPAM charges are eliminated for buy-through customer)
  - Should this valuation instead be at SRP's marginal generation cost, reflecting change in cost as customer departs?
  - Problems with avoided cost-based valuation:
    - Variable valuation over time; possible difficulty in agreeing upon value.
      - Reflected in California and Nevada problems.
    - Need for a contract quantity as the basis for applying avoided cost-based price.
      - Load in the absence of buy-through is not observed.
    - SRP-specific problem: lack of available price of sufficient granularity.

Responsibilities of Contracting Parties

- Responsibilities of SRP, buy-through customers, and GSPs are clearly delineated.
- Account aggregation is barred, at least for project initiation.
  - SRP's argument is administrative.
- SRP's assignment of imbalance settlement to customers appears sensible.
- SRP will continue to provide ancillary services.
  - While not in line with practice elsewhere, Arizona region does not have ancillary service markets as yet. Management's plan appears sensible in this regard.

Relevant Designs/Pricing in the Industry

- Nevada Power / MGM
  - Proceeding describes a principle that the departing customer will "pay the load ratio share of unrecovered adjusted balances in Nevada Power's deferred accounts".
  - Does not specifically mention the fuel clause, but the principle is consistent with SRP's proposal for handling the FPPAM balances.
- California Investor-Owned Utilities Direct Access
  - Power Charge Indifference Adjustment (PCIA) includes an RPS Adder that is similar to SRP's proposed ETAC.
  - However, PCIA (and MGM's Nevada Power settlement) consider the entire generation portfolio whereas SRP limits consideration to a set of older renewable generation assets.
  - PCIA changes annually and has a "vintage" associated with when the customer left the system. SRP may not need to implement a vintage effect because of the limited assets included.
- Green Tariff Power Purchase Agreements
  - Duke Energy Carolinas' Green Source Advantage Rider
    - Large non-residential customers contract with renewable GSPs, continue paying retail tariffs, get hourly marginal avoided cost bill credits (expected hourly marginal production costs and marginal capacity costs for hours in which there are generation constraints)

Summary

- Management's proposal:
  - Allows SRP to meet legislative mandate.
  - Provides large customers with choice of generation service provider.
  - Controls risk: limit to participation, recovers costs, avoids bypass.
  - Uses market-based pricing in providing supporting generation services (imbalance, resupply)
  - Meets design standards of the Board, and of economic theory and industry practice.
  - Responds to anticipated issues/questions with reasonable plans.
    - Examples: ETAC, FPPAM developments, requirements for return to SRP.
  - Is adaptable to future change in regional markets.
  - Is supported by market precedent.

[redacted]

NRG Energy, Inc.
910 Louisiana Street
Houston, Texas 77002

August 4, 2023

SRP Corporate Secretary
Mail Station PAB215
P.O. Box 52025
Phoenix, AZ 85072

RE: NRG Energy's Comments to SRP Regarding its Proposed Buy-Through Program for Large General Service Customers

To Whom It May Concern:

NRG Energy ("NRG") submits this letter as a follow up to the presentations held June 27 and July 18, 2023, regarding SRP's proposed Buy-Through Program for large general service customers. Through its Direct Energy brand, NRG has been an active participant in APS's AG-X buy-through program as a generation service provider ("GSP") since its inception in 2012. From its experience as a GSP and in working closely with customers, NRG has developed a unique understanding of buy-through program design. As a result, NRG provides the following recommendations with the intent to assist SRP in development of a successful customer buy-through program.

NRG is concerned that a number of proposed aspects will be unattractive to GSPs and customers which will limit program benefits, run counter to the intent of the enabling legislation, and run counter to the SRP Board's general principle around Customer Choice. To establish a structure that has the greatest probability for success at the outset, NRG proposes a set of revisions to the proposed program. These include changes to 1) Program Eligibility, 2) the Fuel and Purchased Power Adjustment Mechanism ("FPPAM"), 3) the Buy-Through Charge, 4) Energy Delivery requirements, 5) Imbalance Charges, 6) Returning Customer policy, 7) Approach to Oversubscription, and finally, 8) Minimum Customer Term. NRG's concerns regarding each of these items are detailed in this memo.

Key recommendations for program modifications to improve the chances for program success are the following:

- Program Eligibility
    - Eliminate minimum load factor requirements
    - Allow aggregation of customer accounts to meet the 5 MW minimum threshold and include E-63 customers in the program
- Buy-Through Charge
    - Adjust the charge as FPPAM capacity costs change
    - Adjust the charge as the Early Technology Adjustment ("ETA") costs change and provide greater detail on the ETA contracts

NRG Energy, Inc.
910 Louisiana Street
Houston, Texas 77002

- Energy Delivery
  - Make Palo Verde the default delivery point for GSP energy deliveries
  - Eliminate the requirement that CAISO delivered energy must be a high priority export, for this places a unique, uncompetitive requirement on GSPs
- Imbalance Charges
  - Change the definition of Imbalance to only deviations between scheduled and actual customer load, and not include differences between scheduled and actual energy, which is already addressed in WSPP Schedule C
  - Reduce or eliminate imbalance penalties until concerns regarding "leaning" on imbalance energy can be justified
- Returning Customers
  - The notification period should be reduced to a single year
  - Customers should be placed on SRP's Standard Generation Service if SRP can provide capacity in a shorter timeframe
  - The penalty of $10/MWh or 10 percent of the index price should be eliminated
- Pro rata sharing of a customer's load if the program is oversubscribed should be rejected in favor of a lottery and waitlist
- The requirements for a minimum GSP contract term of one year should be eliminated

In addition, NRG has reviewed the Consultant Report and while there are some aspects that align with NRG's concerns, other statements are unsubstantiated which shows bias toward SRP's interests. The major gap in the Consultant Report as well as SRP's program development is the lack of outreach to either customers or GSPs at the outset. Instead of working collaboratively to develop a program with the greatest chances of success, SRP has focused on SRP's corporate interests, jeopardizing the ability of the program to act as a viable alternative to bundled service.

1. Program Eligibility

A. Load Factor

As proposed, to be eligible for the Program, a customer must have a minimum average monthly load factor of 60 percent. At the June 27 meeting, it was stated that this factor was chosen to help accurately forecast load in real time from customers in the program. SRP staff also stated that if this load factor requirement was eliminated, six additional customers in the E-65 and E-67 rate classes would become eligible. With only 19 customers eligible for enrollment in the program under SRP's currently proposed guidelines[1], adding these additional customers would mean that the majority still would have load factors over 60 percent.

[1] As stated by Staff in the June 27 meeting

Load factor is not ordinarily relevant to customer eligibility in similar buy-through programs and will have little impact on SRP's load forecasts in real time. While APS's AG-X program originally had a load factor minimum at program launch for a subset of customers, this has since been removed from the eligibility criteria. As designed, the current program will represent roughly 2 percent of SRP's peak load. The amount of overall load volatility that would be created by dropping this restriction would be very minimal because, as outlined above, the majority of eligible customers will still have load factors over 60 percent. Also, it is unclear why SRP believes that this restriction will make any difference relative to its current load forecasting efforts. SRP currently creates load forecasts for all E-65 and E-67 customers; while this load will now be scheduled by GSPs, SRP can continue to use its current load forecasting approach to minimize real time forecast errors without imposing this load factor requirement on the program.

In addition, having this restriction creates an unnecessary tracking and administrative barrier to participation. Customers could now be barred from enrollment or potentially removed from the program if their average load factor falls below 60 percent. Instead of creating this unnecessary barrier to customer participation, NRG recommends that the load factor minimum be dropped.

B. Aggregation

During the presentation on June 27th, SRP representatives indicated that customers must have a minimum 5 MW peak load and that aggregation of customers below this peak load to meet the 5 MW minimum would not be allowed. The stated reasoning behind this provision was that it would eliminate operational burdens associated with multiple smaller transactions. However, NRG submits that this rule will unnecessarily limit customer participation and that it stands in contrast to eligibility requirements in similar buy-through programs.

As outlined above, SRP stated in the June 27th meeting that only 19 customers are eligible under the current eligibility rules, representing 0.02 percent of SRP's commercial and industrial customer count per recent US Department of Energy data. While these 19 customers represent 774 MW of peak load, the fact remains that eligibility is severely limited under SRP's proposal and shuts out 99.98% of non-residential customers.

SRP provided further explanations for why it is preventing customer aggregation in the July 18 workshop. Short term, SRP states that it cannot automate its billing system in time to handle aggregations prior to a 2024 launch. SRP's delay in developing the buy-through program to meet statutory obligations for a January 2024 start should not be a reason that aggregation is not allowed. Given the small size of the program, SRP should be able to manually aggregate customer loads until this can be automated. Long-term, SRP states that sufficient load exists to enroll in the program without aggregation, as well as vague concerns about load diversity. While sufficient load exists amongst the 19 customers to fill out the 200 MW cap, the fact remains that the actual number of customers eligible without aggregation is extremely small. SRP should seek to expand eligibility at the outset by allowing aggregation of individual customer sites so that a broader set

NRG Energy, Inc.
910 Louisiana Street
Houston, Texas 77002

of customers and not just the very largest are eligible. At a minimum, the SRP Board should allow aggregation of customers if the program does not fully subscribe after program launch.

C. Rate Class Eligibility

SRP would make the Program available only to customers taking service under the E-65 and E-67 rate schedules. These two rate schedules are for large general service ("LGS") customers that have dedicated substations, which drastically limits the number of customers eligible for participation. To better facilitate participation, the Program should include SRP's standard LGS rate schedule for customers without dedicated substations, E-63. Further, NRG believes that E-63 customers should be able to aggregate their loads and qualify for participation as outlined above. Absent this change, NRG believes the Program is too restrictive and that customers who want buy-through service may not be able to obtain it.

2. FPPAM Charges

The Program will include a component called the FPPAM Settlement Adjustment ("FSA") where any over or undercollection greater than $20MM will be charged or refunded on a pro rata basis to customers enrolling in the buy-through program. As outlined in the published Program Design document, this will be the only FPPAM responsibility for the enrolled customers, with this rider no longer applicable after enrollment in the program. NRG finds this approach reasonable.

Materials presented on July 18 however told a different story with regards to FPPAM responsibility. When detailing what goes into the Capacity Charge, SRP staff showed that enrolled customers would continue to pay a portion of the FPPAM costs that are attributed to capacity:

Class Share of Capacity Costs	
Class Share of Generation Capacity Costs	$132.1M
Class Share of FPPAM Capacity Costs	$38.0M
Class Share of Capacity Costs	$170.1M

This runs counter to the Program Design documents which claim that buy-through customers will no longer be responsible for FPPAM costs. Since FPPAM is a short-term adjustor that is updated on a regular basis, buy-through customers should have their capacity charge associated with FPPAM adjusted as FPPAM changes, and have this portion of the capacity charge removed when the undercollection goes below $20MM. Not doing so creates a situation where buy-through customers have capacity costs locked in at an FPPAM expense level that is no longer valid, creating inequity for buy-through customers

3. Buy-Through Charge

The Program will include a Buy-Through Charge of $4.15 per kW. SRP has indicated that this charge will include three components; 1) an administrative charge of $0.51, 2) a charge for maintaining capacity reserves of $2.87, and 3) a charge for Early Technology Adoption or "ETA" of $0.76. NRG has identified issues with the capacity reserve and ETA charges charge that should be resolved before program implementation.

First, as outlined above, NRG believes that enrolled customers should have their capacity reserve charge adjusted whenever the FPPAM is adjusted to properly reflect their share of FPPAM capacity costs. This would be a simple calculation and not administratively burdensome, as similar adjustments are being made for all other customers. Buy-through customers should also be eligible for a refund of any FPPAM capacity costs if that portion of the FPPAM goes negative and to have the FPPAM capacity cost removed if the total over or undercollection goes below $20MM.

Second, with regards to the ETA charges, SRP has provided insufficient detail to determine if the cost is reasonable. While information was presented in the July 18 meeting regarding the methodology, more information is needed for how the Capacity Value Credit, Energy Value Credit, and Carbon Free Premium Credit is calculated. In addition, NRG believes that much like the capacity cost in the FPPAM, this charge should be revised annually due to the dynamic value of each of the credit modifiers. Finally, more information is needed on the length of the PPAs for the resources in the ETA, with a timeline for when the ETA charges will be removed as the PPAs expire. The Consultant Report agrees that revisions to the ETA charge should be established at the outset of the program.[2]

4. Energy Delivery

NRG supports the use of WSPP Schedule C contracts as being sufficient for energy delivery contracts from GSPs. However, a closer read of the proposal reveals major issues with the energy delivery requirements that may make the program infeasible. The three major issues are:

- Requiring deliveries from the CAISO have high priority export (HPT) status, which would impose a restriction unique to GSPs and CAISO supply
- Requiring delivery with firm transmission to the SRP 230 kV system, which are illiquid supply points with questionable deliverability
- Creates a potential for double billing of differences between planned and actual energy deliveries by using WSPP Schedule C contracts that specify liquidated damages, while billing customers for this same difference as "Imbalance". This issue will be addressed further in the next Section.

[2] CA Energy Consulting Report, Review of Management's Buy-Through Pricing Proposal for SRP, July 27, 2023, p. 20.

NRG Energy, Inc.
910 Louisiana Street
Houston, Texas 77002

a. CAISO Delivery Priority

Section 7.8 of the Draft Program Requirements document states that "the GSP must designate the applicable resource as a "High Priority Export" with CAISO, if the energy is sources from CAISO". This proposal represents a major imposition on GSPs and was not mentioned by SRP in either of the stakeholder meetings.

This proposal likely creates a more restrictive requirement on GSPs than what SRP has imposed on its bundled customers. First, NRG is not aware of any requirement that SRP also requires HPT exports for energy it sources from CAISO that it counts towards its own RA obligations. Second, this requirement goes beyond what has been proposed in the Western Resource Adequacy Program ("WRAP") which SRP plans to join the future. WRAP requires that to count for RA, resources must be either resource specific or an aggregation of resources from a Balancing Authority ("BA") that cannot claim them for their native RA needs. Current CAISO HPT export rules state that HPT will only be assigned to internal-to-CAISO resources with non-RA capacity supporting the export,[3] essentially mandating that only resource specific exports will qualify. APS's proposal to adapt its AG-X program to WRAP rules also does not require HPT status for CAISO exports.

In addition, this proposal does not extend to all imports, just those from the CAISO, and conflicts with WSPP Schedule C delivery requirements that are the legal basis for energy supply. It is unclear why SRP has chosen to single out CAISO; if this additional delivery requirement was deemed important for GSP supply, a requirement for all deliveries beyond what is outlined in WSPP Schedule C would have been specified.

Finally, SRP's proposal ignores the changing approaches that CAISO is considering for assuring energy delivery and that HPT status only relevant during certain market conditions. In the Transmission Service and Market Scheduling Priorities initiative, CAISO is applying for a tariff revision with FERC that would allow exports to obtain HPT status in the month and day ahead if they obtain Available Transfer Capability (ATC) rights.[4] Requiring HPT status for all exports from CAISO regardless of time of year or market conditions invokes an unnecessary burden on GSPs.

Because of the potential inconsistency between SRP's own practices and WRAP requirements, as well as the arbitrary application to CAISO exports and inconsistency with WSPP Schedules, NRG recommends that the requirement for HPT exports from CAISO be struck.

Delivery Location

The Program requires that GSP supplied energy be delivered at a point "approved by SRP". During the June and July workshops, and as outlined in Section 7.3 of the draft Program

---

[3] CAISO Market Operations Business Practice Manual, Section 2.5.5.1
[4] See https://stakeholdercenter.caiso.com/StakeholderInitiatives/Transmission-service-and-market-scheduling-priorities

Requirements, SRP staff stated that locations on SRP's 230 kV loop are the preferred delivery points.

For the program to be successful, SRP must accept delivery at liquid trading hubs that can be accessed by GSPs. Requiring delivery to locations where there is limited or no transmission availability would threaten the viability of the program and unnecessarily raise costs for customers. For this reason, NRG recommends that the Program use the Palo Verde hub as the default delivery point that can be used by GSPs, with other delivery locations permitted only if mutually acceptable to both SRP and the GSP. This is the structure that has been successfully adopted in the APS AG-X buy-through program.

The approach being taken by SRP for Resupply highlights the challenges for delivery of electricity at anywhere other than Palo Verde. SRP will be charging customers Resupply costs based on index pricing at Palo Verde, since this location is "characterized by a large volume of transactions" which "offers a reliable basis for contracting" as highlighted in the Consultant Report.[5] If SRP will be using the Palo Verde hub as the source to Resupply customers, GSPs should be given the same ability to provide Program energy.

5. Imbalance Charges

a. Definition of Imbalance

SRP has defined "Energy Imbalance" in the Program Design documents as "the difference between the hourly delivered energy from the GSP…and the actual Customer Participating Metered Energy". Per this definition, the customer is responsible under "Imbalance" for both deviations between its planned and actual load and deviations between planned and actual energy deliveries. This definition runs counter to how imbalance is calculated in other programs and how deviations in delivered energy are compensated under WSPP Schedule C contracts.[6] Having customers pay for "Imbalance" covered by liquidated damages under WSPP Schedule C energy delivery contracts could lead to charging both the GSP and customer for deviations between energy scheduled and delivered.

Under WSPP Schedule C, deviations between scheduled and actual energy deliveries are addressed in Section C-3.7, which states allowable reasons for interruptions, that neither Seller nor Purchaser shall be obligated to pay damages for certain allowable reasons, and that Section 21.3 of the WSPP Agreement will govern as the basis for damages for non-allowable reasons. Section 21.3 identifies how damages are calculated, namely as the difference between the contract price and the replacement price. Section 21.3(b) states that this approach "represent the sole and exclusive remedy". By now having a definition of Energy Imbalance that includes deviations under WSPP Schedule C energy deliveries, SRP may be in violation of the already established compensation approach.

---

[5] CA Energy Consulting Report, p.16

[6] See https://www.wspp.org/pages/documents/08_26_22_current_effective_agreement.pdf for a sample WSPP agreement

APS recognizes the difference between energy supply and customer demand when defining Imbalance. Under the AG-X tariff, differences between scheduled and actual energy supply are compensated via liquidated damages under the WSPP Schedule C agreement. Only differences between scheduled and actual customer load are compensated via Imbalance Charges. NRG recommends that the same structure should be established under SRP's buy-through program by changing the definition of Energy Imbalance to "the difference between the hourly ***scheduled*** energy from the GSP…and the actual Customer Participating Metered Energy". This approach will be consistent with having Imbalance Penalties assessed on the customer only, to prevent the unfounded concern that a customer will intentionally under forecast load to take advantage of low LAP prices, as expressed in the Consultant Report.[7]

b. Imbalance Penalties

SRP plans to assess severe penalties in the event that energy delivered by the GSP does not align with the customer's load. Under the current proposal, SRP will charge the customer the applicable CAISO Load Aggregation Point (LAP) price for hourly deviations of up to 15% or 2 MW, whichever is greater. For deviations greater than this amount, SRP will charge the customer the 125% of the LAP price for providing imbalance energy. These penalties are excessive and well beyond those imposed by APS for the AG-X program ($3/MWh). Moreover, because imbalances are cleared at the CAISO LAP, SRP will be fully compensated for any imbalance energy, making a penalty of this nature an anticompetitive aspect of the program.

When asked about these penalties during the June and July workshops, SRP responded that they are concerned about "leaning" on imbalance energy. These concerns are entirely unjustified. First, neither SRP nor the Consultant Report provided evidence from market data or the many years of the AG-X program with its much lower imbalance penalty of "leaning" by GSPs or customers. Second, GSPs have no incentive to "lean" on imbalance energy to supply customers. GSPs manage their procurement and customer contracts by assuring that the price paid for delivered energy will be covered by the price paid by the customer. GSPs that "lean" on imbalance energy from the LAP will be exposed to market prices that cannot be hedged, potentially exposing the GSP to significant financial losses. Finally, the other aspect of the imbalance penalty, a GSP's expulsion from the program if imbalances occur in more than 20% of the hours in a calendar month, is a significant incentive in and of itself to minimize imbalances.

For these reasons, NRG recommends reducing, if not eliminating, these penalties. Alternatively, NRG recommends broadening the deviation thresholds well beyond 15%/2 MW. If, once experience is gained after program launch, SRP can identify that "leaning" is occurring to the detriment to the SRP system, only then should the SRP Board consider imposing penalty levels for significant imbalance deviations.

[7] CA Energy Consulting Report, p. 17

NRG Energy, Inc.
910 Louisiana Street
Houston, Texas 77002

6. Returning Customer Notification Timing and Market Rates

As proposed, the Program features an unusually long three-year notice requirement for return to SRP bundled service. If customers return to SRP without providing three-year notice, SRP will provide energy to the customer at its Resupply Energy rates, defined as index pricing plus the greater of $10/MWh or 10 percent of the index price. SRP justifies this lengthy notice period as the amount of time that would be necessary to provide replacement capacity for returning customers, assuming that new capacity would need to be built to supply returning customers.

NRG is opposed both to the length of the notification period as well as the adders to the Resupply Energy rates as being anticompetitive. Customers may be disincentivized to join the program due to the risk of facing unnecessary Resupply Energy penalties for a long period of time. SRP staff stated in the July 18 meeting that it is possible to provide capacity for returning customers on a timeframe shorter than three years if the capacity is available in the market. This is seemingly what SRP has been recently successful in doing for its bundled customers. The inclusion of capacity costs in the short-term FPPAM shows that it is now common for SRP to buy capacity in the short-term market as needed and include the costs in FPPAM, not fixed generation charges. The Consultant Report also states that the notification period is "a potentially significant barrier to participation" and that the tariff should have flexibility to provide shorter notification periods.[8]

In addition, the proposed penalty structure – which uses the greater of $10 per MWh or 10 percent of index pricing – is excessive and unnecessary. NRG agrees that nonparticipating customers should not face any costs if a buy-through customer returns to utility service. Having a returning customer go on an index rate that reflects the wholesale price to meet customer needs prevents any cost shift to bunded customers; enacting a penalty rate is simply an anticompetitive structure that is largely unnecessary for risk mitigation. While the Consultant Report states that SRP is "entitled" to charge a premium, that obtaining index energy comes with a price, and that it reflects what APS does in their AG-X program,[9] this line of argument is unpersuasive and runs counter to the SRP Board Principle of "relationship of prices to underlying costs".[10] Neither SRP nor the Consultant Report provides any evidence of what the actual cost is to procure index energy to justify this fee besides it being a risk factor to keep customers on bundled service. In addition, the Consultant Report ignores programs where returning customers on short notice from competitive suppliers pay no fee.[11]

SRP's proposals mirror recent changes proposed by APS for AG-X in their current rate case but are even more restrictive. NRG and Calpine Solutions have filed comments on the APS proposals that are relevant to this portion of the SRP program design and are reflected below:

[8] CA Energy Consulting Report, p. 19.
[9] CA Energy Consulting Report, p. 18
[10] CA Energy Consulting Report, p. 12
[11] Customers of California's Direct Access program which provide less than six month notice to return to bundled service are place on an index price (Transitional Bundled Service, TBS) with no additional fee

NRG Energy, Inc.
910 Louisiana Street
Houston, Texas 77002

- The notification period for a customer returning to SRP bundled service should be reduced to a single year, which is also the current timeframe that the APS AG-X program uses for notification.
- The program should be modified to state that SRP will serve the customer with SRP's Standard Generation Service sooner than expiration of the notice period if SRP determines that it can do so without adversely impacting other cost-of-service customers. The Consultant Report states that SRP intends to include language that "they will attempt to acquire the necessary capacity in less time, if possible"[12]; this language should be developed before the launch of the program and shared with stakeholders.
- The penalty of $10/MWh or 10 percent of the index price should be eliminated. Alternatively, SRP could follow the APS tariff by stating that SRP will have the "option" to serve the customer with market index priced power plus a penalty in some instances, if SRP can demonstrate that additional costs are necessary to protect nonparticipating customers from any costs due to returning customers. SRP would need to define criteria for how to make that decision within the Program Guidelines.

Other options that should also be considered by SRP to reduce or eliminate the three-year notification period include:

- Placing the customer on an interruptible service tariff, as recommended in the Consultant Report.[13]
- Giving the GSP the option to have full customer capacity requirements, not just the reserve requirements, provided by SRP. This would be similar to what APS is proposing for AG-X in its current rate case. The customer capacity cost should be calculated by starting with the bundled customer capacity charge, minus the energy value from this capacity that is now freed up due to departing load.

7. Oversubscription Approach

In the July 18th meeting, SRP staff stated that if the program is oversubscribed, all enrolled customers will have their participation level reduced on a pro rata basis. This would mean that in an oversubscription situation, a customer will have a portion of their energy demand served by SRP and a portion by a GSP.

NRG is opposed to this approach due to the added complexity and uncertainty that it would bring. If served by both SRP and a GSP, it would be challenging to appropriately assign and track responsibility for daily customer load variation as well as responsibility for long-term customer load changes. While SRP staff stated in the July 18th meeting that all responsibilities will be shared on a pro rata basis, this may be difficult to enact within SRP's billing and tracking systems. If a customer has deviations from its daily forecasted load that leads to Imbalance penalties, it will be impossible to determine the deviations that is assigned to each scheduling party. For example, for

[12] CA Energy Consulting Report, page 13, footnote 31.
[13] CA Energy Consulting Report, page 19

a customer with a 50 MW load shared on a 4/1 basis between a GSP and SRP (40 MW and 10 MW), if a customer used 40 MW instead, how would it be determined which party forecasted incorrectly? Sharing the imbalance on a pro rata basis would not be fair, as a party that badly forecasts load would benefit. In an extreme example, if one party forecasted accurately for their share and another party entered no forecast (zero), the party that forecasted accurately would, incorrectly, be penalized under a pro rata approach.

Instead of pro rata sharing of load responsibilities, NRG recommends a lottery and waitlist approach for initial enrollment, with the waitlist added to afterwards on a first-come, first-served basis. This will allow the full load of each customer to be served by a GSP, eliminating the complexities and challenges of splitting load between a GSP and SRP under this program.

8. Customer Contract Term

Section 4.3 of the draft Program Requirements document states that each GSP contract with a customer must have a term of at least one year. SRP has provided no support for why this requirement has been proposed. Customers should have the flexibility to sign contracts for shorter durations if desired, provided that the term is agreed to by a GSP and that the GSP can meet the timing requirements for Energy Scheduling as outlined in Section 7 of the Program Requirements document. NRG recommends that the one-year minimum term be removed. Alternatively, SRP could require a minimum one-year term when customers initial depart SRP bundled service, with no contract length requirements following this initial obligation.

Consultant Report Concerns

SRP contracted with Christensen Associates to provide a review of the buy-through program proposal regarding the costing, pricing, and statutory requirements. The major gap in the Consultant Report as well as SRP's program development is the lack of outreach to either customers or GSPs at the outset. Instead of working collaboratively to develop a program with the greatest chances of success, SRP and Christensen Associates have focused on SRP's corporate interests, jeopardizing the ability of the program to act as a viable alternative to bundled service. While SRP has held two stakeholder meetings to discuss the program in June and July, these meetings were held after the initial program structure was already proposed to the Board. If the concerns of customers and GSPs were truly under consideration, SRP would have instructed their Consultant to perform outreach as part of their scope to determine perspectives other than SRP's.

Aspects of the Consultant Report have been incorporated in previous sections that outline NRG's recommendations. NRG appreciates that the report reflects concerns mentioned by NRG, including that the ETA charge should be updated on a regular basis, that Palo Verde is the most liquid hub for energy transactions in the region, and that the three-year notification period for returning customers should be reconsidered. However, there are other statements in the Consultant Report which show bias toward SRP's interests in program development, as they are unsubstantiated without any evidence. These include:

NRG Energy, Inc.
910 Louisiana Street
Houston, Texas 77002

- Concerns that customers will intentionally under forecast load to take advantage of LAP prices charged for Imbalance. Theoretical scenarios are outlined with no supporting data.
- Stating that SRP is "entitled" to charge a premium for Resupply Energy, without any analysis for what a reasonable, non-punitive premium should be.

Conclusion

NRG appreciates your attention regarding these aspects of the Program. It is our hope that this letter will help facilitate discussion and changes on each aspect outlined above. We look forward to continuing to work with SRP to develop the Program to ensure that it is a success.

Sincerely,

\S\

Scott Olson
Director, Western US Regulatory Affairs
NRG Energy

<u>SRP BUY-THROUGH PROGRAM</u>

<u>ARIZONA LARGE CUSTOMER GROUP'S COMMENTS</u>

The Arizona Large Customer Group ("AZLCG"), by and through its counsel, Holland & Hart LLP, respectfully provides these informal comments regarding the SRP Buy-Through Program.

I. INTRODUCTION

The AZLCG has a vested interest in designing and participating in mutually beneficial utility buy-through programs in Arizona in order to provide participants with reasonably priced and reliable electric energy, as well as an opportunity to further individual participant procurement preferences, corporate goals, and initiatives. The AZLCG appreciates SRP's willingness to engage stakeholders in the design phase of its Buy-Through Program. These comments are intended to provide issues for discussion at SRP's July 18, 2023 stakeholder workshop and reflect the AZLCG's initial position on these issues. Following the conclusion of the July 18th stakeholder workshop, the AZLCG may provide more detailed comments for SRP's consideration.

II. THE AZLCG'S COMMENTS

Based on the presentation and discussion following SRP's June 27, 2023 stakeholder workshop, several aspects of SRP's Buy-Through Program necessitate further explanation, discussion, and potential revision. Rather than submitting detailed positions at this nascent stage, the AZLCG provides the below list of issues and initial positions as a guide to further discussion at the July 18, 2023 stakeholder workshop:

<u>Program Limits and Participation Requirements</u>

Topic 1. Reevaluation of program participation limits

The AZLCG does not support arbitrary limits on participation on Buy-Through programs. Rather customers meeting eligibility requirements should be able to evaluate their benefits and potential risks of participating in the program and make the business decision to participate or not without utility imposed artificial constraints. However, if program participation limits remain, the AZLCG recommends evaluating these limits (as well as eligibility and participation criteria) based on customer interest at regular intervals specified in the tariff. For example, the tariff could include a provision stating that SRP will reevaluate Buy-Through Program requirements and participation limits every three years with stakeholder input.

Topic 2. Allocation of program participation

The Buy-Through Program is currently proposed with a 200 MW program participation limit. However, it is unclear how participants will be selected in the event that more customers subscribe than the participation limit allows. SRP has not provided any reasoning or justification for this participation limit. It is important to provide fair, non-discriminatory services to all customers, and it is widely accepted industry practice to segregate customers by eligibility requirements. If eligible customer subscriptions exceed the Buy-Through Program size, how will SRP determine which of its customers get to participate? Will SRP allocate the participation limited Buy-Through Program on a pro-rata share? A first-come-first-served basis? Or on a lottery system? Or other method? Which, if any, of these methods is most fair and non-discriminating to current and future customers? While this dilemma helps demonstrate why arbitrary limits on participation are problematic, the AZLCG requests information on how SRP is justifying these participation limits and how SRP intends to allocate scarce program participation under such limits.

Topic 3. Participant load growth

Customers that are awarded participation in the Buy-Through Program will be commercial and industrial customers with a variety of business goals. These business goals may include expansion with resulting increases to electric load. The current structure of the Buy-Through Program requires participants to commit 100% of their Annual Peak Demand, unless, as pertinent for this issue, the participant's load is greater than 50 MW. This presents several scenarios and associated questions regarding how future load growth will be handled.

- If a participant's load is 30 MW at subscription, but then increases their load by 20 MW: Is this customer's behind-the-meter growth part of the Buy-Through Program or subject to fully bundled rates? Does it matter if the Buy-Through Program participation limit is fully subscribed? Does it matter if the 100% Annual Peak Demand requirement is violated?
- If a participant's load is 40 MW at subscription, but then increases their load by 30 MW: Is this customer's behind-the-meter growth part of the Buy-Through Program or subject to fully bundled rates? Will any of the customer's behind-the-meter growth be eligible for SRP's Full Electric Service Requirements Rider (FESR)? If this customer's metered load factor is 96% but the load factor for the portion of load on fully bundled rates is 76% is the customer eligible for SRP's Large Extra High Load Factor Substation LGS (E-67) rate? If the program if fully subscribed when the customer increases their load, the participant will either be in violation of the 100% demand commitment or the participation limit. How does SRP intend to remedy this issue?
- If a participant's load is 40 MW at subscription, but then decreases by 5 MW: Will the customer's participation allocation be reduced and made available to new participants? Will the customer's participation allocation be automatically awarded

to a participant who may be in violation of the 100% Annual Peak Demand requirement?

These are additional problematic scenarios that are both foreseeable and probable, and they are primarily caused by the introduction of an arbitrary program participation limit. Accordingly, the AZLCG requests discussion on this topic and recommends that SRP remove the participation limit. If SRP is unwilling to remove the participation limit, AZLCG recommends SRP remove both the 100% Annual Peak Demand requirement and the 50 MW individual participant limit to eliminate incompatibilities with program design and allow those customers who elect 100% Annual Peak Demand participation to have any and all future load growth eligible for Buy-Through Program participation regardless of Buy-Through Program participation limits imposed upon initial subscription.

Topic 4. Aggregation of multiple customer accounts

Aggregation is commonplace in Buy-Through programs or their equivalents in other utility service territories and states. One or more otherwise qualifying commercial and industrial customers should not be precluded from participating in the Buy-Through Program simply because the annual demand associated with any single delivery point is not high enough, provided that customers can meet participating thresholds across multiple service accounts on the SRP system. SRP has not provided any justification or reasoning regarding why this additional participation limit is being placed on the Buy-Through Program. The AZLCG recommends that customers be permitted to aggregate their loads for purposes of any demand minimum requirement. At a minimum, a customer with multiple service accounts under common ownership should be permitted to aggregate load in order to meet demand requirements. The AZLCG requests discussion on this topic and reconsideration of the Buy-Through Program as it is currently proposed.

Topic 5. New load participation

The Buy-Through Program limits participation to those entities with a minimum Annual Peak Demand of 5 MW. Annual Peak Demand is defined as: "The maximum thirty-minute integrated kW demand for the Customer account, as measured by the meter, over a 12-month period. This amount will be based on the 12-month period immediately preceding the Customer's initial enrollment in the Program, unless recalculated as set forth in the Program Requirements." Because the potential participant must have demand data for the preceding 12 months, the Program appears to require new large load customers to take bundled service until 12 months of data demonstrate that it meets the peak demand floor. AZLCG recommends if a customer is eligible for any of the E-65/E-66/E-67/CPP price plans or has sufficient aggregated demand using the E-61/E-63 price plans that the customer is automatically eligible for the Buy-Through Program rider. The AZLCG requests further discussion regarding why a new large load customer could not sign up for the Buy-Through Program and recommends that the Buy-Through Program be modified to accommodate those customers that can reasonably demonstrate that their annual peak demand will exceed applicable minimums by a date specified. This modification to the program seems particularly beneficial to SRP and its customers in an era of exceptionally tight generation capacity markets.

<u>*Program Charges*</u>

Topic 6. Basis for each component of the Buy-Through Charge.

The Buy-Through Charge is proposed to equal $4.15/kW, comprised of the following components:

$2.87 – Reserve Capacity Charge

$0.76 – Early Technology Charge

$0.51 – Administrative Charge

SRP has provided no justification or cost basis for how these costs were calculated to determine if they accurately recover the actual costs that Buy-Through participants may be causing on the system. The AZLCG requests a detailed explanation with calculations of the cost components of each charge.

Topic 7. Fuel and Purchased Power Adjustment Mechanism ("FPPAM") and the FPPAM Settlement Adjustment ("FSA")

Over the period in which the FPPAM rose to its current amount of approximately $400M under-collected, SRP's combined net revenues ("CNR"), excluding fair value adjustments on outstanding fuel and purchased power contracts, were substantially positive ($47M in FY20, $173M in FY21, $13M in FY22, and $39M in FY23). The AZLCG requests an explanation as to how the cumulative under-collections in fuel and purchased power expenses did not yield substantially negative CNR results in recent years. In particular, if over-recovery of non-fuel expenses materially offset the contemporaneous under-recovery of fuel expenses during this period, AZLCG seeks to understand why potential direct assignment of FSA costs to Buy-Through participants is reasonable.

Topic 8. Stranded Costs

SRP is one of the fastest growing utilities in the country. Buy-Through participants have the ability to significantly reduce SRP's need for resource acquisitions and investments in an era of exceptionally scarce and expensive generation capacity markets. SRP and its remaining customers stand to benefit greatly through the willingness of Buy-Through Program participants to incur the upfront costs of higher marginal costs for capacity and energy than SRP's current resource mix and bear the volatility of that market. The avoided cost of new generation requirements and associated benefits to SRP's remaining generation customers has not been acknowledged or allocated to Buy-Through Program participants in any of the proposed charges. The AZLCG suggests that the Early Technology Charge assigned to Buy-Through Program participants be offset with these benefits.

Topic 9. Mechanics of fully bundled rates above the individual participant limitation

Although AZLCG's recommendation is to eliminate the 50 MW individual participant limitation, if SRP retains this program element AZLCG requests clarification of the mechanics of how fully bundled rates would be applied to participants. The Buy-Through Program permits a single customer account to participate in the program up to 50 MW. Any amount over 50 MW would be served under the applicable bundled rate schedule. However, it is unclear how separate charges for the 50 MW, on the one hand, and the remaining load, on the other hand, would apply in the instance of a customer account with multiple meters. For example, one meter on that account may have a load factor of 100%, while another may have a load factor of 30%. Which portion of the participants overall load is to be considered within the 50 MW individual participation limit would have impacts on the charges the customer would pay. The AZLCG recommends that the Buy-Through participant be permitted to designate for each account which specific meters, up to the 50 MW limit, are subject to the program as compared to fully bundled rates and requests further discussion on how charges will be assessed when a participant is limited by the 50 MW individual participant limit.

Operations and Scheduling

Topic 10. Imbalances

The Buy-Through Program tariff applies an imbalance settlement at CAISO LAP price or when significant scheduling errors occur a punitive 75% (over-scheduled) or 125% (under-scheduled) penalty of the "applicable LAP price." The Federal Energy Regulatory Commission's ("FERC"), April 24th 1996 Order (Order No. 888) specifically required all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to file open access non-discriminatory transmission tariffs. While imbalance service is standard, SRP's non-discriminatory costs for these services are well documented in Schedule 4 of SRP's Open Access Transmission Tariff ("OATT"), effective August 1, 2022. However, the punitive penalty for scheduling errors is not included in SRP's OATT. Charging an additional or greater penalty for imbalances through the Buy-Through Program appears to be discriminatory to GSPs and ultimately Buy-Through Program participants utilizing this standard service. SRP has provided no justification or reasoning why GSPs and Buy-Through Program participants engaging in standard wholesale transactions with SRP should receive a punitive penalty when no other market participant utilizing their system does. The AZLCG requests further discussion and justification on the punitive penalties included for Buy-Through Program participants but not included in SRP's OATT.

Topic 11. Line losses

The Buy-Through Program tariff includes line losses of 4.14%. The Program Requirements document includes line losses of 4.32%. Accordingly, there appears to be ambiguity regarding the appropriate line loss percentage. Notwithstanding the different percentages, the line loss percentage is not adequately justified. For those participants taking service at the transmission level, SRP's loss factor is 3.24% (per the SRP OATT), and distribution line losses should not apply. The AZLCG requests further discussion on the appropriate line loss percentage and the basis for the same.

Miscellaneous

Topic 12. Reserve capacity and ability to self-provide

As stated above, the Buy-Through Program contemplates a $2.87 Reserve Capacity Charge. It appears the charge is intended to recover the costs of providing capacity sufficient to meet a 16% planning reserve margin on the participant's participating load. As an initial matter, reserve capacity charges intended to provide resource adequacy have not been sufficiently justified or supported by cost. This is especially true where, as here, participating customers are large energy users with high load factors and *contracted* load. Deviations in contracted load are rare, particularly as compared to residential customers, for whom a planning reserve margin finds greater justification. However, to the extent that resource adequacy requirements remain, participants should have the option to self-supply through their GSP.

Topic 13. Selection of GSP

The Buy-Through Program tariff and program requirements require that GSPs meet SRP's creditworthiness and other counterparty standards. These are not defined and could, if unreasonably onerous, restrict or eliminate the pool of eligible GSPs. The AZLCG recommends that the requirements for GSPs be clearly defined and detailed in supporting documentation to avoid changing, discriminatory, or overly restrictive standards that are unable to provide any credit risk mitigation to SRP and its remaining customers.

Topic 14. Program certainty

There is significant risk on the part of any Buy-Through Program participant and GSP when contracting for new energy resources. As mentioned previously in Topic 8, SRP's load growth is among the highest in the nation at a time when generation capacity markets in the West are exceptionally tight. All new load growth must be met with new generation resources which are increasingly costly, especially vis-à-vis existing resources. Buy-Through Program participants and/or their GSPs will almost certainly need to make long-term financial commitments, which may include investment in generation assets, to ensure themselves of future firm supplies. However, to the extent that the Buy-Through Program is subject to cancellation or modification at any time, participants and GSPs could be faced with significant stranded costs in that event. Similar to the 3-year notice of return period for participants to cancel participation in the program, the AZLCG recommends that participants receive some certainty in their participation in order to provide assurance to participants when making these financial commitments. As a result, Buy-Through Program participants require a 10-year notice of cancellation of the Buy-Through Program from SRP.

III. CONCLUSION

The AZLCG supports all programs that give customers choice. While the Buy-Through Program was a legislatively mandated program, AZLCG encourages SRP to consider additional offerings in the Sustainable Energy Opportunity program and Market Price Pilot Rider. Furthermore, AZLCG strongly encourages SRP to remove currently proposed arbitrary participation limits on the Buy-Through Program to resolve many of the program element incompatibilities discussed herein, to allow for a flexible and manageable program for customers over time, and to ensure that all similarly situated customers are provided fair and non-discriminatory service offerings through SRP's rates. AZLCG appreciates the opportunity to submit these initial comments regarding SRP's Buy-Through Program and looks forward to engaging with the SRP and other stakeholders through this process.

Respectfully submitted July 14, 2023.

HOLLAND & HART LLP

By: ________________________________

Austin W. Jensen, #038143
Thorvald A. Nelson
Holland & Hart LLP
555 17th Street, Suite 3200
Denver, CO 80202
Tel: (303) 295-8000
awjensen@hollandhart.com
tnelson@hollandhart.com

ATTORNEYS FOR THE ARIZONA LARGE CUSTOMER GROUP

30111254_v4

SRP is in receipt of the comments submitted on behalf of the Arizona Large Customer Group (AZLCG) regarding SRP's proposed Buy-Through Program (the "Program"). SRP management values AZLCG's feedback and is pleased to provide these responses to supplement SRP management's responses to these issues that were addressed at the July 18th Stakeholder meeting. The numbered items below correspond to the topics enumerated in AZLCG's submission.

1. *Reevaluation of program participation limits*

   As an initial matter, please note that Arizona Revised Statutes Section 30-810 requires SRP to offer a buy-through program that includes terms, conditions, and limitations, including a minimum qualifying load and maximum amount of program participation. The Program conditions and limitations proposed by SRP management were carefully considered, and designed to meet statutory requirements, and ensure that SRP can effectively manage and administer the Program, while allowing meaningful customer participation.

   As discussed in the July 18th Stakeholder Engagement meeting, the following are the primary drivers behind the Program participation requirements and limits proposed by SRP management:

   - Minimum load factor of 60%: Accounts with a lower load factor are more likely to require excessive load-following and experience energy imbalances
   - Minimum peak demand of 5 MW: Makes the Program accessible to smaller accounts, while avoiding burdens of integrating many small resources
   - Participation cap of 50 MW: Ensures that Program capacity is available to a significant number of customers

Management anticipates that the foregoing conditions will be re-evaluated over time once SRP and customers have some experience with the program as proposed. Any changes would be contemplated during a future public meeting as part of a process to address the program.

2. *Allocation of program participation*

   Please refer to Appendix B of the Program Requirements, and see slide 11 of the July 18th Stakeholder presentation:
   https://www.srpnet.com/price-plans/business-electric/large-general-service/buy-through

   If the Program is oversubscribed during the initial launch, SRP will allocate Program capacity on a pro-rata basis. After initial launch, Program will be first-come, first-served.

3. *Participant load growth*

   Please refer to Appendix B of the Program Requirements: https://www.srpnet.com/price-plans/business-electric/large-general-service/buy-through

   As detailed in the Program Requirements, SRP will allow for 15% customer growth or shrinkage before adjusting the Customer Participating Load (CPL) and Customer Participation Factor (CPF). If the Customer's load grows, and there is space available in the Program, new load may be subscribed, in which case the CPL will be appropriately increased. If, however, the Program is fully subscribed, the new load will be non-participating load and the Customer may join the waitlist to increase their CPL. The requirement that the Customer Participating Load must equal 100% of the Annual Peak Demand is subject to the 50 MW cap.

4. *Aggregation of multiple customer accounts*

   Please refer to slide 13 of the July 18th Stakeholder presentation:
   https://www.srpnet.com/price-plans/business-electric/large-general-service/buy-through

Management anticipates that this aspect of the Program will be re-evaluated during a future public meeting.

5. *New load participation*

   A Customer that is otherwise eligible may subscribe after one day of usage and is not required to have pre-existing data for 12 months. As with all Customers, the Customer's CPL and CPF will be subject to adjustment on an annual basis.

6. *Basis for each component of the Buy-Through Charge*

   Please refer to slides 3 – 8 of the July 18th Stakeholder presentation: https://www.srpnet.com/price-plans/business-electric/large-general-service/buy-through

   More detailed calculations are provided in Attachment A.

7. *Fuel and Purchased Power Adjustment Mechanism ("FPPAM") and the FPPAM Settlement Adjustment ("FSA")*

   As discussed in the July 18th Stakeholder Engagement meeting, FPPAM is a stand-alone mechanism separate from broader financial performance. SRP is not obligated to credit the under-collection balance when Combined Net Revenue (CNR) performance exceeds expectations. Similarly, when CNR performance does not meet expectations, SRP does not increase the FPPAM balance owed by customers.

   Having said that, during the period in which the under-collection accumulated (fully captured by FY21-23), SRP CNR (excluding fair value adjustments) totaled $225M. During that same period, SRP voluntarily forwent $206M, which means SRP effectively already provided over 90% of the offset suggested.

8. *Stranded costs*

   As discussed in the July 18th Stakeholder Engagement meeting, the Program proposal is based on an embedded-cost approach, under which the Customer does not pay for generation services. This approach provides more certainty and consistency than a marginal-cost approach based on estimated costs avoided. Buy-Through arrangements typically credit based on embedded cost, even when the avoided cost of capacity is lower than the embedded cost. If a marginal approach were used, it would be applied regardless of market conditions, including at times when capacity prices are more attractive.

   Additionally, marginal costs are fluid, and the appropriate methodology for determining avoided costs could be prone to significant debate. Conversely, embedded costs are determined in a transparent public price process requiring Board approval.

   The Early Technology Adoption (ETA) is consistent with established precedent in Arizona regarding recovery of legacy renewable costs from buy-through customers. The ETA only recovers above-market costs. Therefore, the carbon-free value, energy value and capacity value were subtracted from the cost basis in the calculation of the ETA charge.

9. *Mechanics of fully bundled rates above the individual participant*

   In the instance of a Customer account with multiple meters, the sum of those meters will be considered as the account load.

   Please refer to Appendix B of the Program Requirements: https://www.srpnet.com/price-plans/business-electric/large-general-service/buy-through

Customers must participate with 100% of the load on their account, subject to adjustment based on the 50 MW cap, available capacity in the Program, and/or participation in Concurrent Programs (as defined in the Program Requirements document).

A Customer who participates with less than 100% of their load will be a partial participant, and the Customer Participation Factor will be calculated such that SRP and the Customer to share a prorated portion of the customer's hourly usage and load-following.

The Customer Participation Factor is used to calculate Customer Participating Metered Energy and Customer Participating Billing Demand.

The demand (kW) and energy (kWh) not constituting Customer Participating Billing Demand or Customer Participating Metered Energy will be served on the Customer's retail price plan.

10. *Imbalances*

Buy-Through Customers are SRP retail electric customers, not standard wholesale customers. In the wholesale market, if a generator fails to generate at committed levels, there are consequences beyond imbalance charges. Additionally, in the Energy Imbalance Market (EIM), a member must commit participating generation units and show resource sufficiency as a prerequisite to participation. Buy-Through is different in that the GSP's obligation is directly tied to specific retail customer load and other costs/credits/adjustments are at play that don't apply to a wholesale transmission transaction.

To be clear, the Program was designed with the assumption that the Customer will arrange for delivery, as required, of WSPP schedule C firm energy. The EIM is a cost optimization tool, not a resource adequacy tool. It is not a firm product and thus not an appropriate index for treatment of anything other than a small amount of unintentional imbalance (of which Management's proposal of a 15% bandwidth is a very generous application).

The proposed imbalance settlement method reflects the need for hourly or more granular market pricing and public availability of pricing. An alternative method would have been to use a market more reflective of the energy product that a Customer commits to provide, such as PV ICE index, and shaping that index based on an hourly index such as CAISO hourly day ahead or EIM prices.

For context, over the past three years, the PV ICE price has exceeded the EIM price on average by over 44%. This demonstrates the impact of not providing the committed generation source and why an escalator is appropriate and needed.

From a grid planning perspective, a fully subscribed Buy-Through Program may replace 200 MW that SRP would have otherwise had to procure. If SRP sends a price signal, like EIM, that is too low for a firm product, it could incent Customers to under schedule generation and buy the difference at EIM prices. If those Customers were no longer contributing 200 MW of capacity to SRP's grid, then SRP's resource adequacy would be weakened.

Additionally, the Customer's Generation and FPPAM credits in the Buy-Through Program are calculated as though they fully offset the Customer's load in SRP's resource planning process. If they do not, the Customer is over-credited. By sending an accurate price signal, SRP incentivizes the Customer to schedule generation to match their hourly load as accurately as possible and thus substantially provide for their own capacity needs as intended, and as assumed in the Program pricing design.

11. *Line losses*

Upon further review, Management intends to revise its proposal to reduce the value for line losses to 3.32%, to better reflect losses for only those customers who are eligible for the Program.

With this change, the Program Requirements will be revised to reflect that when calculating the load schedule, the Customer or the GSP (not both) should account for losses by increasing the forecasted load by 3.43%, so that after sustaining line losses of 3.32%, the original forecasted load amount remains.

For example, if a Customer wants 9.668 MWh but 3.32% of the MWh will be lost in delivery within SRP’s system, the GSP should deliver 10 MWh to the SRP system so that after losses, 9.668 MWh is delivered to the customer’s location. The factor given by 10 / 9.668 results in 1.0343 or an increase of 3.43%.

12. *Reserve capacity and ability to self-provide*

As discussed in the July 18th Stakeholder Engagement meeting, PRM of 16% is appropriate for all customers regardless of load factor, as it is an adjustment to account for generation outages, and not whether any one load does or doesn't materialize as the question suggests.

After SRP gathers data and gains experience managing the Buy-Through Program, management may consider proposing an option for self-provided reserves.

13. *Selection of GSP*

Management will add language in the Program documents regarding GSP requirements.

Requirements for credit approval include:

1) WSPP membership
2) a long-term issuer or senior unsecured debt rating from both Moody’s and S&P, or an implied rating as determined by SRP, of at least BBB- (or its equivalent)
3) ownership of assets in the United States

For counterparties that do not meet (2) above, acceptable forms of credit support include:

a) Parent Guarantee from a qualified guarantor that meets the ratings requirement and owns assets in the U.S.
b) Letter of Credit from a U.S. bank (or domestic branch of a foreign bank) with a senior debt rating of at least A (or its equivalent)
c) cash margin deposit

14. *Program certainty*

Management is considering whether modifications would be appropriate to partially satisfy this request.

BUY-THROUGH CHARGE

	Line Number	Source		Total
System Determinants				
Annual kWh	[1]	FP24 Budget V7 - FY25		37,171,553,973
E65 Class Determinants				
Annual kWh	[2]	2019 E-67 Rate Design Tables		4,755,596,000
Annual kW	[3]	2019 E-67 Rate Design Tables		8,174,702
Buy-Through Class Determinants				
Total Program Capacity (kW)	[4]			200,000
Average Monthly Peak of Eligible Customers (kW)	[5]	FY23 Billing Data		26,569
Average Annual Peak of Eligible Customers (kW)	[6]	FY23 Billing Data		29,397
Demand Conversation Factor	[7]	=[5] / [6]		90.38%
Program Monthly Average Billed Capacity (kW)	[8]	=[4] x [7]		180,760
Administration Charge				
Annual Buythrough Admin Costs	[9]	Administrative Costs Table	$	1,113,917
Annual kW in Program	[10]	=[8] x 12 months		2,169,119
Administration Charge per kW	[11]	=[9] / [10]	$	0.5135
Reserve Capacity Charge				
Reserve Requirement	[12]	Planning Reserve Margin (PRM) for FY25		16%
Total Generation, Including Reserves	[13]	=[12] + 100%		116%
Reserve Capacity Ratio	[14]	=[12] / [13]		13.79%
Generation Portion				
Annual Total E65 Allocated Generation Costs	[15]	2019 E-67 Rate Design Tables (Peak and Average)	$	132,104,139
Reserve-Related Share of E65 Allocated Generation Costs	[16]	=[14] x [15]		$18,221,261
Generaton portion of Reserve Capacity Charge per kW	[17]	=[16] / [3]	$	2.23
FPPAM Portion				
Total Capacity-Related costs in FPPAM	[18]	FPPAM Capacity Table	$	327,554,542
Reserve-Related Share of capacity-related FPPAM costs	[19]	=[14] x [18]	$	45,179,936.79
Class Share of Capacity-Related Costs	[20]	2019 Cost Allocation Study Peak and Average (Schedule 6)		11.6%
Allocated FPPAM Costs to Class	[21]	=[19] x [20]	$	5,247,667
FPPAM portion of RC Charge per kW	[22]	=[21] / [3]	$	0.64
Reserve Capacity Charge per kW	[23]	=[22] + [17]	$	2.8709
Early Technology Adoption Charge (ETA)				

Annual Actual Cost of ETA Assets	[24]	FP24 Budget V7 - FY25	$ 104,301,270
Annual Generation from ETA Assets (kWh)	[25]	FP24 Budget V7 - FY25	773,881,450
Energy Portion			
Market Value of ETA Energy	[26]		$ 38,988,804
Carbon Mitigation Portion			
Carbon Free Premium ($ per kWh)	[27]	Solar Choice Plus Program	$ 0.005
Value of Carbon Free Premium	[28]	=[25] x [27]	$ 3,869,407
Capacity Portion			
Capacity Value of ETA Assets	[29]		$ 7,674,726
FP24 Value of Carbon Free Energy and Capacity	[30]	=[26] + [28] + [29]	$ 50,532,937
FP24 Projected Above Market Costs of ETA	[31]	=[24] - [30]	$ 53,768,332
Class Share of ETA Costs	[32]	2019 Cost Allocation Study Peak and Average (Schedule 6)	11.6%
Allocated ETA Costs to Class	[33]	=[31] x [32]	$ 6,245,213
Early Technology Adoption Charge (ETA) per kW	[34]	=[33] / [3]	$ 0.7640
Total Buy-Through Charge (Reserves, Admin, ETA) per kW	[35]	=[11] + [23] + [34]	$ 4.1484

FPPAM SETTLEMENT EXAMPLE

	Line Number	Source	Total
FPPAM Settlement Adjustment (FSA) for Sample Customer			
Example FPPAM Balance on 1/1/2024 in Excess of $20M	[1]		$ 380,000,000.00
Sample Customer Energy Usage 6/1/2021 - 1/1/2024 (kWh)	[2]		250,000,000
SRP Total Energy Served 6/1/2021 - 1/1/2024 (kWh)	[3]		85,000,000,000
Customer Portion of SRP Energy Served 6/1/2021 - 1/1/2024	[4]	=[2] x [3]	0.29%
Individual Buy-Through Customer FSA Responsibility	[5]	=[1] x [4]	$ 1,117,647
Monthly FSA Charge to Sample Customer (36 Month Annualization)	[6]	=[5] / 36	$ 31,045.75

E-65 & E-67 Rate Design

PRICES

Monthly Service Charge

	Proposed E-65 (May 2018-April 2019 billing cycle)	Proposed E-67 (May 2019 billing cycle)
Billing and Customer Service	$4,286.75	$4,286.75
Meter (per billing meter)	$207.42	$207.42
Total (with one meter)	**$4,494.17**	**$4,494.17**

Monthly Facilities Charge — Customer Specific – See Facilities Rider

Per kW Charge

Summer	On-Peak Max kW	Max kW
Transmission	$1.56	$2.74
Transmission Cost Adjustment	$0.00	$0.00
Ancillary Services 1-2	$0.00	$0.45
Ancillary Services 3-6	$0.00	$0.58
Generation	$5.36	$13.00
Total	**$6.92**	**$16.77**

Summer Peak	On-Peak Max kW	Max kW
Transmission	cation	$3.77
Transmission Cost Adjustment	$0.00	$0.00
Ancillary Services 1-2	$0.00	$0.45
Ancillary Services 3-6	$0.00	$0.59
Generation	$12.33	$22.49
Total	**$14.83**	**$27.30**

Winter	On-Peak Max kW	Max kW
Transmission	$0.38	$0.74
Transmission Cost Adjustment	$0.00	$0.00
Ancillary Services 1-2	$0.00	$0.21
Ancillary Services 3-6	$0.00	$0.54
Generation	$2.63	$8.50
Total	**$3.01**	**$9.99**

Per kWh Charges (All kWh)

Summer	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh
Distribution Delivery	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Transmission	$0.0042	$0.0038	$0.0001	$0.0000	$0.0000	$0.0000
Transmission Cost Adjustment	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Ancillary Services 1-2	$0.0015	$0.0015	$0.0000	$0.0000	$0.0000	$0.0000
Ancillary Services 3-6	$0.0010	$0.0010	$0.0010	$0.0000	$0.0000	$0.0000
System Benefits	$0.0029	$0.0029	$0.0029	$0.0029	$0.0029	$0.0029
Environmental Programs Adjustment	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Generation	$0.0226	$0.0225	$0.0154	$0.0077	$0.0071	$0.0041
Fuel and Purchased Power	$0.0253	$0.0253	$0.0253	$0.0253	$0.0253	$0.0253
Total	**$0.0575**	**$0.0570**	**$0.0447**	**$0.0359**	**$0.0353**	**$0.0323**

Summer Peak	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh
Distribution Delivery	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Transmission	$0.0070	$0.0039	$0.0001	$0.0000	$0.0000	$0.0000
Transmission Cost Adjustment	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Ancillary Services 1-2	$0.0016	$0.0016	$0.0000	$0.0000	$0.0000	$0.0000
Ancillary Services 3-6	$0.0010	$0.0010	$0.0010	$0.0000	$0.0000	$0.0000
System Benefits	$0.0029	$0.0029	$0.0029	$0.0029	$0.0029	$0.0029
Environmental Programs Adjustment	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Generation	$0.0471	$0.0362	$0.0242	$0.0221	$0.0162	$0.0094
Fuel and Purchased Power	$0.0253	$0.0253	$0.0253	$0.0253	$0.0253	$0.0253
Total	**$0.0849**	**$0.0709**	**$0.0535**	**$0.0503**	**$0.0444**	**$0.0376**

Winter	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh
Distribution Delivery	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Transmission	$0.0021	$0.0020	$0.0001	$0.0000	$0.0000	$0.0000
Transmission Cost Adjustment	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Ancillary Services 1-2	$0.0015	$0.0015	$0.0000	$0.0000	$0.0000	$0.0000
Ancillary Services 3-6	$0.0010	$0.0009	$0.0009	$0.0000	$0.0000	$0.0000
System Benefits	$0.0029	$0.0029	$0.0029	$0.0029	$0.0029	$0.0029
Environmental Programs Adjustment	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Generation	$0.0181	$0.0177	$0.0124	$0.0066	$0.0060	$0.0028
Fuel and Purchased Power	$0.0235	$0.0235	$0.0235	$0.0235	$0.0235	$0.0235
Total	**$0.0491**	**$0.0485**	**$0.0398**	**$0.0330**	**$0.0324**	**$0.0292**

Billing Determinants

E-65

	# of Accts
Billing and Customer Service	564
Meter (per billing meter)	792

Per kW Charge	On-Peak Max kW	Max kW
Summer	2,623,608	2,722,441
Summer Peak	1,441,709	1,503,710
Winter	3,723,625	3,948,552

(Each per kW value is printed on each of the five component rows: Transmission, Transmission Cost Adjustment, Ancillary Services 1-2, Ancillary Services 3-6, Generation.)

Per kWh Charges	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh
Summer	337,272,262	470,001,910	803,533,828
Summer Peak	174,706,990	243,531,628	415,677,382
Winter	271,398,357	277,319,817	1,762,153,826

(Each per kWh value is printed on each of the nine component rows, Distribution Delivery through Fuel and Purchased Power.)

Total kW	Total kWh
15,963,644	4,755,596,000

REVENUES

Monthly Service Charge

E-67	Proposed E-65 (May 2018-April 2019 billing cycle)	Proposed E-67 (May 2019 billing cycle)
Billing and Customer Service	$2,417,727	$2,417,727
Meter (per billing meter)	$164,277	$164,277
Total (with one meter)	**$2,582,004**	**$2,582,004**

Monthly Facilities Charge — Customer Specific – See Facilities Rider

Per kW Charge

Summer	On-Peak Max kW	Max kW
Transmission	$4,092,829	$7,459,487
Transmission Cost Adjustment	$0	$0
Ancillary Services 1-2	$0	$1,225,098
Ancillary Services 3-6	$0	$1,579,016
Generation	$14,062,541	$35,391,727
Total	**$18,155,371**	**$45,655,328**

Summer Peak	On-Peak Max kW	Max kW
Transmission	$3,604,272	$5,668,987
Transmission Cost Adjustment	$0	$0
Ancillary Services 1-2	$0	$676,670
Ancillary Services 3-6	$0	$887,189
Generation	$17,776,269	$33,818,442
Total	**$21,380,541**	**$41,051,288**

Winter	On-Peak Max kW	Max kW
Transmission	$1,414,977	$2,921,928
Transmission Cost Adjustment	$0	$0
Ancillary Services 1-2	$0	$829,196
Ancillary Services 3-6	$0	$2,132,218
Generation	$9,793,133	$33,562,688
Total	**$11,208,110**	**$39,446,030**

Per kWh Charges (All kWh)

Summer	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh
Distribution Delivery	$0	$0	$0	$0	$0	$0
Transmission	$1,416,544	$1,786,007	$80,353	$0	$0	$0
Transmission Cost Adjustment	$0	$0	$0	$0	$0	$0
Ancillary Services 1-2	$505,908	$705,003	$0	$0	$0	$0
Ancillary Services 3-6	$337,272	$470,002	$803,534	$0	$0	$0
System Benefits	$978,090	$1,363,006	$2,330,248	$978,090	$1,363,006	$2,330,248
Environmental Programs Adjustment	$0	$0	$0	$0	$0	$0
Generation	$7,622,353	$10,575,043	$12,374,421	$2,596,996	$3,337,014	$3,294,489
Fuel and Purchased Power	$8,532,988	$11,891,048	$20,329,406	$8,532,988	$11,891,048	$20,329,406
Total	**$19,393,155**	**$26,790,109**	**$35,917,962**	**$12,108,074**	**$16,591,067**	**$25,954,143**

Summer Peak	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh
Distribution Delivery	$0	$0	$0	$0	$0	$0
Transmission	$1,222,949	$949,773	$41,568	$0	$0	$0
Transmission Cost Adjustment	$0	$0	$0	$0	$0	$0
Ancillary Services 1-2	$279,531	$389,651	$0	$0	$0	$0
Ancillary Services 3-6	$174,707	$243,532	$415,677	$0	$0	$0
System Benefits	$506,650	$706,242	$1,205,464	$506,650	$706,242	$1,205,464
Environmental Programs Adjustment	$0	$0	$0	$0	$0	$0
Generation	$8,228,699	$8,815,845	$10,059,393	$3,861,024	$3,945,212	$3,907,367
Fuel and Purchased Power	$4,420,087	$6,161,350	$10,516,638	$4,420,087	$6,161,350	$10,516,638
Total	**$14,832,623**	**$17,266,392**	**$22,238,740**	**$8,787,762**	**$10,812,804**	**$15,629,470**

Winter	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh	On-Peak kWh	Shoulder-Peak kWh	Off-Peak kWh
Distribution Delivery	$0	$0	$0	$0	$0	$0
Transmission	$569,937	$554,640	$176,215	$0	$0	$0
Transmission Cost Adjustment	$0	$0	$0	$0	$0	$0
Ancillary Services 1-2	$407,098	$415,980	$0	$0	$0	$0
Ancillary Services 3-6	$271,398	$249,588	$1,585,938	$0	$0	$0
System Benefits	$787,055	$804,227	$5,110,246	$787,055	$804,227	$5,110,246
Environmental Programs Adjustment	$0	$0	$0	$0	$0	$0
Generation	$4,912,310	$4,908,561	$21,850,707	$1,791,229	$1,663,919	$4,934,031
Fuel and Purchased Power	$6,377,861	$6,517,016	$41,410,615	$6,377,861	$6,517,016	$41,410,615
Total	**$13,325,659**	**$13,450,011**	**$70,133,722**	**$8,956,146**	**$8,985,162**	**$51,454,892**

	Current	Proposed
Special Adjustments	**$4,116,033**	**$4,116,033**
Aggregation Discount	($1,426,679)	($1,426,679)
Total E-67	**$289,363,755**	**$290,703,524**

ADMINISTRATIVE

	Line Number	Source	Total
<u>**Annual Buy-through admin costs**</u>			
Startup costs			
Startup costs	[1]		$ 748,011.08
Years of Annualization	[2]		5
Total Startup Cost (5yr Annualization)	[3]	[1] / [2]	$ 149,602.22
Ongoing annual costs			
Ongoing Annual Costs	[4]		$ 964,314.89
SRP annual Buy-Through admin costs	[5]	=[3] + [4]	$ 1,113,917.11

FPPAM CAPACITY COSTS

	Line Number	Source	Total
<u>FPPAM Capacity Costs Table</u>			
Power Supply Agreements	[1]		$ 371,146,734.13
Energy Value Credit of Bundled Solar	[2]		$ 43,592,192.38
Total Capacity-Related costs in FPPAM	[3]	=[1] - [2]	$ 327,554,541.75