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Scott Olson
Director, Western US Regulatory Affairs
NRG Energy
910 Louisiana Street
Houston, Texas 77002

Re: SRP Response to NRG August 4, 2023 letter regarding the SRP Proposed Buy-Through Program

August 25, 2023

Dear Scott,

This letter will acknowledge and respond to the NRG August 4, 2023 letter sent to the SRP Corporate Secretary Office relative to the SRP Proposed Buy-Through Program that was presented on an informational basis to the SRP Board of Directors on August 10, 2023. SRP management provided a copy of your August 4, 2023 letter to the SRP Board Members, and also provided a copy to Christensen and Associates, the Board independent Consultant advising the Board on the proposed Buy-Through Program.

As you will recall, NRG was allowed to make an oral presentation to the SRP Board on August 10, 2023 and SRP Management shared at that meeting that it would formally respond to the NRG August 4, letter. SRP's response is attached hereto and will also be provided to the SRP Board of Directors and make part of the record for the Board to consider. SRP appreciates NRG's proposals in this process to date and would be happy to have any additional discussion or comments with you at any time. As you know the SRP Board will formally consider the approval of the Buy-Through Program at its September 26, 2023 Special Board Meeting.

Sincerely,

Adam Peterson

Adam Peterson
Director Corporate Pricing

Attachment: SRP Management Response to NRG August 4, 2023 Letter regarding Buy-through Program
August 25, 2023

With respect to the NRG August 4th letter, SRP Management provides the following supplemental comments organized to respond as set forth in your letter. The numbered items and headings below correspond to the topics enumerated in NRG's letter.

1. Program Eligibility

A. Load Factor

SRP's Buy-Through program is a "bring your own power program" that assumes customers will bring energy and capacity to offset their load at any given time but will have use of SRP's generation system for reserves/backup services and ancillary services. As a general proposition, low load factor customers are likely to have a much "peakier" and more "variable load" than high load factor customers. They are also likely to lack the scale, forecasting ability, and high run rates that would enable them to predict their load and match their load with sufficient accuracy. For those reasons, SRP Management believes it is unlikely that a low load factor customer will be able to successfully manage the load-matching requirements of the Program.

SRP Management continues to recommend the inclusion of the proposed minimum load factor to help ensure participants in the Program are able to successfully comply with the Program design requirements of providing generation that closely matches customer usage.

B. Aggregation

SRP Management summarized some of the reasons for excluding aggregation in slide 13 of the July 18th stakeholder meeting presentation. In addition, SRP Management discussed this topic during the August 10th Special Board meeting. SRP Management continues to believe that its concerns set forth are significant, and that the SRP Buy-Through Program should not allow aggregation at this time:

1. Timing / Feasibility
   With SRP's existing systems, administration of the Program, as proposed, will require manual billing of anywhere from 4 to 26 accounts. From an internal review of this issue to the extent aggregation was considered, there would potentially be an additional 58 customers that meet the Program requirements, representing over 10,000 accounts. Due to the significant labor and potential for error involved in manual billing, billing that many accounts would need to be executed through billing system automation, which cannot be feasibly implemented before January 1, 2024, the date by which SRP is legally required to offer the Program. Additionally, SRP is planning to retire and replace its current billing system in 2026. The upgrades required to handle billing aggregation are significant and it would not be prudent to make such upgrades to the current system only to retire the system shortly thereafter.

2. Cost Relation
   The automation upgrades that would be required to accommodate billing aggregation would add significantly higher administrative costs to the Program. If the Program has low participation (as is initially expected due to current market energy prices), the additional administrative cost of the change would not be recovered from the Program participants and thus would result in an impermissible cost shift to SRP's other customers.

3. Program Design Impacts
   As designed, the Program doesn't account for appropriate charges that would need to apply to accounts from the various rates aggregation would introduce. Updates would need to be made to accommodate these different load and cost profiles to avoid introducing cost shifts. Additionally, SRP Management notes that if aggregation were allowed, other Program accommodations, such as allowing partial participation to participants in other SRP programs, would need to be revisited and potentially revised as those accommodations could not be supported at a much higher volume.

SRP Management continues to recommend against permitting aggregation to meet qualifying load levels. As stated at the August 10th, 2023 Board meeting, SRP can review the aggregation issue in the future when there may be sufficient participating customers to bear the additional administrative costs and SRP's current billing system has been replaced.

C. Rate Class Eligibility

NRG has proposed enlarging the eligibility to the Program by adding the SRP E-63 customer class. In evaluating this proposal, SRP has determined allowing E-63 customers to participate in the Program does not materially change the Buy-through Charge, as it still rounds to $4.15/kW. However, should E-63 customers be included, specific Program terms would require modification. For example, line losses for E-63 customers would be 4.14%, instead of 3.32% for dedicated substation E-65/E-67 customers.

SRP Management recommends accepting the NRG suggestion to modify the program to include E-63 customers in the Program, with the addition of the line loss clarification mentioned above.

2. Fuel and Purchased Power Adjustment Mechanism (FPPAM) Charges

Adjust the charge as FPPAM capacity costs change

Contrary to the assertion in NRG's letter, the Program materials have consistently stated that while the FPPAM billing component will not apply to Customer Participating Metered Energy, the Buy-Through Charge includes portions of the generation and FPPAM charges that should not be bypassed. In particular, the first document posted to SRP's Buy-Through website, labeled "Buy-Through Program Overview," expressly states that "[t]he capacity charges [in the form of the Reserve Capacity Charge] are derived from capacity charges in the generation component of E65/67 rates as approved in 2019 and capacity related costs included in FPPAM."[1] In the July 18 stakeholder session, Management provided additional detail on the Buy-Through Charge, all of which was consistent with Program documents and prior presentations.

Under the Program proposal, participating customers would bypass 97.5% of FPPAM charges, but continue to pay about 2.5% of FPPAM charges that are included in the Reserve Capacity Charge component of the Buy-Through Charge. As indicated in the Program Overview document, that 2.5% accounts for the capacity costs in FPPAM, allocated using factors from the Cost Allocation Study in Support of Proposed Adjustments to SRP's Standard Electric Price Plans Effective with the May 2019 Billing Cycle.

[1] Buy-Through Program Overview, pg4, paragraph 4 https://www.srpnet.com/assets/srpnet/pdf/price-plans/business-electric/Buy-Through-Program-Overview.pdf

SRP Management agrees it is appropriate to update rate calculations over time to incorporate current cost and usage characteristics. SRP intends to review and if appropriate, update rate calculations when SRP develops cost studies as part of a future price process.

3. *Buy-Through Charge*

Adjust the Reserve Capacity Charge whenever the FPPAM is adjusted, and adjust the ETA Charge annually

Regarding the suggestion of a refund of the portion of the Reserve Capacity Charge associated with FPPAM capacity costs, it is not clear how the capacity costs in FPPAM could become a negative, therefore such a refund would not be applicable. Similarly, it would not be appropriate to remove the FPPAM capacity contribution to the Reserve Capacity Charge if the FPPAM collection balance were below $20M.

SRP Management agrees it is appropriate to update rate calculations over time to incorporate current cost and usage characteristics. SRP intends to review and if appropriate, update rate calculations when SRP develops cost studies as part of a future price process.

Provide greater detail on the ETA Charge

The Capacity Value Credit, Energy Value Credit, and Carbon Free Premium Credit are calculated as follows:

$$\begin{aligned} &Energy\ Value\ Credit \\ &\qquad = FY24\ Hourly\ Projected\ Generation \\ &\qquad \times Hourly\ CAISO\ Day\ Ahead\ Market\ @\ Palo\ Verde\ Node\ 3yr\ Average \end{aligned}$$

$$\begin{aligned} &Capacity\ Value\ Credit \\ &\qquad = Effective\ Load\ Carrying\ Capability\ of\ ETA\ FLeet \\ &\qquad \times 2020\ Marginal\ Cost\ Study\ Demand\ Cost\ (\$70.41\ per\ kW - year) \end{aligned}$$

$$\begin{aligned} &Carbon\ Fee\ Premium\ Credit \\ &\qquad = FY24\ Hourly\ Projected\ Generation \\ &\qquad \times Solar\ Choice\ Plus\ Carbon\ Free\ Credit\ (\$0.005\ per\ kWh) \end{aligned}$$

The five resources currently included in the ETA Charge expire in the following years:

Generating Plant	Contract Expiration
Dry Lake 1	2029
Dry Lake 2	2029
Hudson Ranch 1 Geo	2042
Cooper Crossing Solar Phase 1	2036
Queen Creek Solar	2032

4. *Energy Delivery*

<u>Remove requirement that deliveries from the CAISO have high priority export (HPT) status</u>

Following events of the August 2020 heat wave in the desert southwest which resulted in rotating electricity outages in California, in April 2021 the California Independent System Operator (CAISO) implemented changes to their market and transmission rules that effectively reduce the priority of the majority of export energy transactions. These changes have resulted in several volume reductions to SRP purchases that were either made directly with CAISO or through a third-party marketer who was sourcing the transaction with CAISO energy. Most recently, this was observed on July 25th and 26th, 2023, when system conditions and regional demand caused CAISO to begin reducing or rejecting export energy in both the day-ahead trading and the hour-ahead trading environments.

When purchasing energy to demonstrate and meet SRP's planning and adequacy requirements, SRP transacts for the purpose of obtaining firm energy to serve load. The CAISO's tariff does not provide for firm energy exports, unless a transaction is (1) with a specified resource that is not designated for Resource Adequacy with CAISO, and (2) registered in advance to qualify for HPT status. However, wheel-through transactions qualifying for HPT status are subject to pro-rata curtailment with CAISO load under certain conditions. As such, these qualified HPT transactions do not meet the definition of a firm transaction, but SRP acknowledges that the HPT transaction priority is the most correlated product available from CAISO to the requirement of a firm energy product.

In its August 4, 2023 letter, NRG stated that an HPT requirement exceeds the standard that the Western Resource Adequacy Program (WRAP) proposes for Resource Adequacy (RA), and that SRP only places this transmission requirement on energy from CAISO. However, it is also true that beginning in August 2020, and as recently as July 2023, CAISO is the only BAA in the Western Interconnection that manages its transmission system to bias import preferences for its own load at the expense of wheels that rely on firm transmission rights, rather than place wheel-through transactions used to serve load outside the CAISO on even footing with imports to serve CAISO load.

SRP Management does not consider energy to be "firm" unless there is firm transmission to deliver it to SRP's system. The energy environment is dynamic in the West, with CAISO, Southwest Power Pool (SPP) and Western Power Pool (WPP) each conducting highly technical stakeholder working groups to contemplate new rules that may coexist in entirely new market constructs such as CAISO's Extended Day-Ahead Market, SPP's Markets+ and WPP's WRAP.

Given the ongoing evolution of the western energy markets, SRP Management recommends modifying the proposal to remove the HPT requirement at this time. Given this ongoing evolution, and the importance of a "firm" energy resource, SRP Management further recommends that the issue be monitored and potentially reconsidered in the future as the markets develop.

<u>NRG recommends that the Program use the Palo Verde hub as the default delivery point that can be used by GSPs</u>

While it's often easiest for any market participant to transact at a major transmission hub like Palo Verde, transacting at such a hub is not equivalent to delivering energy to SRP's system. Energy delivered to Palo Verde will necessarily require the purchase of an additional transmission path in order to transmit that energy from Palo Verde to SRP's 230 kV system. SRP has the same constraint when SRP purchases wholesale energy at Palo Verde to meet load and reserve requirements. For example, this summer SRP made multiple energy purchases to provide for summer reliability and then, unless the seller provided the transmission capacity and included the costs in the contract price, SRP was required to purchase transmission capacity from third parties to import the energy to SRP's 230 kV system. At this time, there is available transmission capacity posted on OASIS by third parties that may be purchased to deliver energy from Palo Verde (and other trading hubs) to SRP's 230 kV system. That cost should be borne by the Customer – not SRP.

To assist customers with the transmission delivery challenges described above, SRP Management recommends modifying the proposal to provide the following options:

Option 1: The GSP may deliver energy to any mutually agreed point on SRP's transmission system.

Option 2: If SRP has available transmission capacity from Palo Verde to SRP's 230 kV system posted on OASIS, the GSP may use the capacity without charge to schedule the energy to SRP's 230 kV system for purpose of meeting customer load under this program. Currently, SRP does not have any such available transmission capacity.

Option 3: The Customer may direct SRP to purchase available firm transmission capacity from a third party to support the GSP's delivery of Buy-Through energy to SRP's 230 kV system. The customer will be responsible for the full cost of that reservation, and SRP will charge the customer accordingly through a separate agreement.

5. *Imbalance Charges*

A. *Definition of Imbalance*

It is SRP Management's intention that the Buy-Through Customer will be the recipient of any liquidated damages payable by the GSP under the WSPP Agreement. This will be detailed in the service contract(s) executed by SRP, the Customer and the GSP. Therefore, there will be no double recovery of costs resulting from charging Buy-Through customers for imbalance.

B. *Imbalance Adjustments*

Buy-Through customers are SRP retail electric customers, not standard wholesale customers. In the wholesale market, if a GSP fails to generate at committed levels, they may incur substantial liquidated damages. 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 do not apply to a wholesale transaction.

To be clear, the SRP Program proposal was designed with the assumption that the customer will purchase 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 reasonable application).

The SRP Management proposed imbalance settlement method addresses the need for granular, publicly available market 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%.[2] This demonstrates the impact of not providing the committed generation source and why an escalator is appropriate and needed. While not equivalent to the energy a customer commits to provide, CAISO hourly day ahead is another market where additional energy can be sourced. CAISO hourly day ahead price has exceeded the EIM price on average by 28%[3] during the past three years. Both markets demonstrate that where additional resources can be accessed, prices are higher than EIM prices. These markets become more applicable as variances move past minor imbalances and towards larger variances where SRP may need to acquire new supplies to address regular shortages and are part of the rationale of the adjusted EIM values for Tier 2 imbalance.

From a grid planning perspective, a fully subscribed Buy-Through Program may replace 200 MW of capacity 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 incentivize 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, a 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 a more appropriate price signal, SRP incentivizes customers 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.

Management does not recommend any changes to the proposed imbalance settlements.

6. *Returning Customer Notification Timing and Market Rates*

Prior to the August 10, 2023 SRP Board meeting, SRP Management modified its proposal to allow some flexibility, for a customer's return to standard retail service. Please see the updated program documents made available to the Board and posted to SRP's website on Monday, August 7th, 2023. In essence, the changes allow a customer to exit the Program with less than three years notice if SRP determines that it has, or can obtain, capacity without shifting costs to other customers.

The adder included in the Resupply Price reflects the expected additional costs associated with a physical product liquidity[4] premium and custom hourly profile typically below 100% load factor. On a forward basis, the PV ICE index represents a financial hedge. Typically, acquiring the physical product results in an additional premium. It is seasonal and creates increased volatility. PV ICE products also only represent standard on- and off-peak block products so while PV ICE is used as the basis of the

[2] Source: CAISO Western Energy Imbalance Market @ Palo Verde Node vs Palo Verde Peak or Off-peak Intercontinental Exchange (PV ICE) Day Ahead Power

[3] Source: CAISO Western Energy Imbalance Market @ Palo Verde Node vs Day-Ahead Market @ Palo Verde Node

[4] As used in this context, liquidity refers to times when there is a limited supply of firm (G-F) energy in the market

Resupply Price, the index price alone would not include the cost of any load shaping necessary to serve any variations in load below 100% load factor or fractional megawatts of load[5]. The index adder also helps ensure that, should SRP have to incur increased transmission cost to get energy from a trading hub to the SRP system (which is often the case during summer months), those costs are not shifted to non-participating customers.

As alluded to in NRG's letter, in recent years with limited availability of capacity in the region, SRP has entered into short-notice power supply agreements. Those have been priced from 36% to 67% higher than the price of the contemporaneous proposed Resupply Price, indicating that the inclusion of the adder is an appropriate mechanism for avoiding cost shifts to other customers.

SRP Management believes that the changes recommended prior to and addressed at the August 10th Special Board meeting address concerns regarding notice requirements and are appropriate. Accordingly, SRP Management does not recommend any further changes to the proposal with regards to return to standard retail notice and Resupply Price.

7. *Oversubscription Approach*

In developing the Program proposal, SRP Management considered using a lottery approach in the event of Program oversubscription. However, SRP's Strategic Energy Managers met with several of SRP's largest customers and learned that their preference was generally for a pro-rata allocation, rather than a lottery system. Those customers favored the hybrid approach proposed by SRP Management, where a proportionate allocation is made only if, during initial Program enrollment, subscription requests exceed the 200 MW Program capacity. After the Program is fully subscribed, Program participation will be on first come, first served basis, with a wait list available if necessary.

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 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 applicable retail price plan.

SRP Management does not recommend changes with respect to the oversubscription approach.

8. *Customer Contract Term*

SRP Management proposed a minimum GSP contract duration of 12 months to largely align with the cadence of WRAP forward showings, so SRP can demonstrate summer capacity seven months ahead.

[5] On-peak refers to the 16-hour time block from hours ending 7:00am to 10:00pm Pacific Prevailing Time (PPT), Monday through Saturday, excluding NERC designated holidays. Off-peak refers to hours ending 1:00am through 6:00am and hours ending 11:00pm and 12:00am PPT, Monday through Saturday, all hours on Sunday and NERC designated holidays. NERC designated holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. In the event that New Year's Day, Independence Day or Christmas fall on a Sunday, the NERC holiday is celebrated the Monday immediately following that Sunday. If these days fall on a Saturday, the NERC holiday remains on that Saturday.

Before SRP performs its first binding WRAP Forward Showing in November 2025 for summer 2026, SRP will modify contract duration terms to align with WRAP requirements.

SRP Management does not recommend shortening the minimum contract duration since a shorter contract may not cover the summer months or peak winter months and therefore does not offer the planning predictability needed to demonstrate resource adequacy.