PDR-DERP-NGR-LFA Summary Comparison Matrix

Proxy Demand Response (PDR), Distributed Energy Resource Provider (DERP), Non Generator Resource (NGR), and Load Forecast Adjustment (LFA) Program Elements

<table>
<tr><th>Market Participation Model</th><th>Proxy Demand Resource (PDR)</th><th>Distributed Energy Resource (DER) Provider</th><th>Non-Generating Resource (NGR)</th><th>Western Energy Imbalance Market DR
Load Forecast Adjustment (LFA)</th></tr>
<tr><td>Description</td>
<td>1. Proxy Demand Response (PDR) is a market participation model that enables 3rd parties to bid demand response into the CAISO market independent of the Load Serving Entity for load curtailment in wholesale Energy and Ancillary Services markets
2. PDR – Load Shift Resource (PDR-LSR) is a market participation model allowing for a bidirectional dispatch product that rewards PDRs for increasing consumption during negative pricing (i.e., oversupply events).
3. Reliability Demand Response Resource (RDRR) is a market participation model for reliability-based load curtailment, triggered only under certain emergency conditions (starting at EEA Watch). RDRRs have different requirements and limitations.</td>
<td>DER Provider (DERP) is a market participation model that allows for an aggregation of Distributed Energy Resources (DERs) allowed within limitations to meet minimum capacity requirements and act as one ‘virtual’ resource (see also the DERP Agreement template).
• [Review the Distributed Energy Resources Provider webpage for more information]</td>
<td>Non-Generating Resource (NGR) is a resource-type market participation model (i.e., such as a conventional generator), created to account for the positive-negative range of a storage resource. It may either act as a storage resource—or, if providing generation-only, as a conventional generator.
Note A resource-type participation model, distinguished from non-resource-type participation models like PDR and DERP, may bid into markets directly under its own model <u>or</u> through other participation models (i.e., NGR resources may bid through the NGR model, or it may be used within the PDR or DERP models).
(3) NGR subtypes:
• Limited Energy Storage Resources (LESRs) have a continuous positive to negative operating range according to discharge and charge limits, respectively, and are constrained by their State of Charge (SOC). Batteries and flywheels qualify as LESRs.</td>
<td>Demand-Side DR reduces EIM entities’ baseload forecast (Load Forecast Adjustment) into the real-time market.
• Reduces or increases entities’ shown capacity needed to support load and pass RSE.
  o Required to reduce load
• May reduce accuracy of BAA’s load forecasts used in the market…
  o If DR does not perform to submitted schedule
  o If other elements in demand forecast are driving an expected lower forecast than actual (weather & model)
  o If the quantity is very small in relation to a BAA’s load due to differences in forecasting methods used when present.
• When submitted, always considered in RSE, but may not be recognized in real-time market load forecast
• CAISO works with BAAs to ensure the most accurate load forecast is developed and used.</td></tr>
</table>

	4. Unique rules apply to the ***Participating Load*** model, which includes *Pumped Hydro Storage*. These resources act as load while using energy to pump water to higher elevation reservoirs; then act like generators by creating energy when releasing water back to lower reservoirs. • [Review Section D.5 of the Market Operations BPM and the Storage webpage for more information on *Participating Load*] [Review the material on the Demand Response and Load webpage for more information]		• ***Dispatchable Demand Response (DDR)*** resources have a non-positive operating range (i.e. cannot generate electricity), and they are constrained by their Curtailable Energy Limit. • ***Generic NGRs***, like LESRs, have a continuous positive-to-negative operating range, but they are not constrained by an SOC. **Note** LESRs and DDRs may provide Regulation Energy Management (REM) or act as non-REM resources, while Generic NGRs may *only* provide REM—this distinction determines which market products are accessible to the resource and how capacity is calculated. • [See the Storage webpage for more information]	• [Review the Energy Imbalance Market BPM and EIM Tariff Section 29.34.L.2.D for more information]
Market Participation Options *See the Market Operations BPM for additional information*	• Day-Ahead & Real-Time energy • Day-Ahead & Real-Time Spinning and Non-Spinning reserves ***(PDR and Participating load models only)*** • [See also Section 3.2 of the Market Instruments BPM for additional information]	• Day-Ahead & Real-Time energy • Day-Ahead & Real-Time Spinning and Non-Spinning reserves	**LESR** and **DDR**: • Day-Ahead & Real-Time energy • Day-Ahead & Real-Time Spinning Reserves, Non-Spinning reserves, and Regulation Up & Down **Generic NGR**: • Day-Ahead & Real-Time Regulation Up & Down	**Real-time** • Implicitly valued as a self-schedule • DR deployment is expected and forecasted load reduction shows up ○ No real-time energy imbalance settlement if performs as expected.

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			**Note* Energy and Ancillary Service Awards are co-optimized throughout the optimization horizon*	○ If a program over performs, it could receive a positive real-time energy imbalance load settlement. ○ If it under performs, it could receive a negative real-time energy imbalance load settlement. **Pending EDAM tariff approval:** Day-Ahead option available—similar to Real-time
Capacity & Aggregation Requirements	**Energy markets only**: 100 kW minimum curtailment—must be sustainable for duration of bid. **Ancillary Services**: 500 kW minimum curtailment—must be sustainable for 30 minutes for Spin/Non-Spin awards. Additionally, smaller loads may be aggregated to achieve the minimum; aggregations are not required to be served by a single LSE that is located within the same Sub-LAP. • [See DR/RDRR Overview)]	Aggregation must be 100 kW minimum capacity. Aggregation must be <20 MW in total when spanning multiple P-Nodes. Individual resources within the aggregation must be <1 MW in size and must be located within the same Sub-Lap. • [See the DERP Participation Guide and Checklist for additional information]	500 kW minimum capacity (PMax counts towards this minimum, not just for the qualifying regulation capacity) **Non-REM**: 60-min continuous energy requirement **REM:** 15-min continuous energy requirement **Note* All subtypes may be aggregated* • [See the REM-NGR BRS and REM-NGR Overview for qualifying regulation capacity for DA Awards, as well as for additional information]	Aggregation: resources aggregated across forecast zones within each WEIM BAA Capacity: no minimum requirement
	Note As noted in the NGR section above (pg. 1), individual resources may be of different types (battery/storage, EV-managed charging, conventional gen, etc.)			

Operating & Bidding Characteristics *See the Market Operations BPM, for additional information*	Resource bids in as a supply resource; bid segments may be as granular as 0.01 MW Resource owner defines one start-up and one ramp rate **Note* All bids must lie above the **Net Benefits Test (NBT)** threshold (view NBT results here)*	Pnode resource movement must be "in the same direction as dispatch" (*e.g.*, if the resource is asked to "increase supply," individual sub-resources can move in opposite directions—*i.e.*, discharging by some while others are charging—but the aggregated response at a Pnode must result in an increase in supply at each Pnode). ***Default Distribution Factors*** (DFs) are statically set within the Master File for the resource but can be dynamically reset as part of the resource's schedule or bid. Resources must respond according to these DFs, which apply to both load and generation response collectively. Market resource is evaluated, dispatched, and controlled at the aggregation level. Resource control system is required to manage sub-resource response to a single ISO instruction.	There are two segments of ramp rates Currently, NGRs are modelled with no start-up time and no start-up costs; as such, they are also ineligible for commitment cost recovery. Energy losses are considered during the charging process, not the discharging process. **Non-REM:** DAM and RTM observe State of Charge (SOC) limitations in the energy and ancillary service optimizations. Further, DAM calculates SOC according to prior day's day-ahead schedule if SOC is not included in the DA bids. **REM**: SOC limitations are observed in real-time economic dispatch only. ISO manages SOC. **Note* Other than the Generic NGR subtype, currently, NGRs are not subject to Market Power Mitigation (MPM)* • [See also the REM-NGR BRS Section 4.1, for additional information]	CAISO requires a schedule with five-minute intervals submitted one day prior, updated in real time (up to T-45) Schedule submitted to ShortTermForecasting@caiso.com

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Telemetry *See the Direct Telemetry BPM for additional information*	**Energy** Market: ○ Telemetry not required unless resource is >10 MW ○ Provision of status every 4 seconds ○ Update of status every 360 seconds (maximum); 5-minute scan rate (as defined in the Direct Telemetry BPM) **Ancillary Services** (Spinning & Non-Spinning): ○ Required (at any capacity) ○ Provision of status every 4 seconds ○ Update of status every 60 seconds (maximum) ○ 1-minute scan rate (as defined in the Direct Telemetry BPM)	**Energy** Market: ○ Telemetry not required unless resource is 10 MW or greater **Ancillary Services** (Spinning & Non-Spinning): ○ Required (regardless of capacity) ○ Provision of status every 4 seconds **Note* A DER must securely convey telemetry to the ISO's EMS over the Energy Communication Network (ECN) using one of the ISO approved protocol methods*	**Energy** Market: ○ Telemetry not required unless capacity is >10 MW ○ Provision of status every 4 seconds ○ Update of status every 360 seconds (maximum); 5-minute scan rate **Ancillary Services** (Regulation Up/Down, Spinning & Non-Spinning): ○ Provision of status every 4 seconds ○ Update of status every 4 seconds ▪ 8-second round trip response **Note* **State of Charge** (SOC) optimization requires telemetry, but an SC may choose to self-manage SOC (i.e., an SC may choose not to use energy limits and SOC optimization and may instead manage SOC and risk of non-performance in Real Time)*	No requirement.
Metering *See the Metering BPM for additional information; See the Direct Telemetry*	Metered by ***Scheduling Coordinator (SC)*** ○ LRA-approved meters permitted (thus, utility distribution company (UDC) meters ok) ○ Meter data used in calculating performance of DR resources must include application of Distribution-Loss Factors to revenue quality meter data.	Metered by SC ○ LRA-approved meters permitted (thus, UDC meters ok) ○ In the absence of LRA requirements, ISO has developed default requirements	Metered by ISO *or* SC If ISO-metered: ○ ISO-metered entities require an ISO meter and polling (ISO-metered, polled and processed), or an ISO-approved SC-metered entity approach If SC-metered:	Each resource has a master file inclusion flag, which requires each participating WEIM entity's attestation that only expected increases or reductions in demand provided by its demand response programs will be submitted.

BPM for specific requirements	○ SC submits ***Settlement Quality Meter Data (SQMD)*** as Demand Response Energy Measurement to ISO to represent resource performance ***A statistical sampling*** measurement method may be used to estimate the usage of an aggregated PDR where interval metering is not available for all individual customers. NOTE: Methodology info found in Section 6 of the Demand Response BPM		○ LRA-approved meters permitted (thus, UDC meters ok) ○ In the absence of LRA requirements, ISO has developed default requirements	
Performance Evaluation Methodology for Settlement	Performance is measured as curtailment from *expected* load; SCs use tariff-approved performance methodologies to calculate PDR performance. Methodology details available in Section 4.13.4 of the CAISO tariff. Performance evaluation methodology (PEM) approval process is required. Additional information on approval process can be found in Section 5 of the Demand Response BPM. **Note** ○ *DA energy can be settled on hourly meter data* ○ *RT and A/S is settled on 5 minute data, which can be estimated from 15 minute meter data*	Submit ***SQMD*** to ISO by applying ***Distribution-Loss Factors*** to revenue quality meter data. **Note* SQMD is required to be submitted from the SC on a daily basis for all market intervals 24/7—i.e., not just when scheduled or received pursuant to an ISO dispatch*	NGR Real-Time bids utilize ***State of Charge (SOC)*** values from 4-second cycle Telemetry signals. ISO ***Energy Management System (EMS)*** passes SOC values to the ISO Real Time Market every 1 minute. **Note* 24/7 resource availability required—i.e., metered and settled 24/7 on metered quantity, thus, must always schedule or bid into the market when operating or will incur an **Uninstructed Deviation Energy** payment/charge when operating and not bidding/scheduling*	See above [Metering]

	○ *For Ancillary Services, a* ***No-Pay Charge*** *is evaluated for Spinning and Non-Spinning Reserve Settlement based on meter readings before and after—this rescinds Day-Ahead and Real-Time Reserve Capacity Awards payments for the service to the extent that the resource that was awarded the Reserve Capacity does not fulfill the requirements associated with that payment*			
ISO Contract Requirements	Demand Response Provider Agreement (DRPA). Please refer to Tariff Appendix B for all Pro Forma Agreements	DERP Agreement (DERPA) if aggregating to meet .5 MW minimum size requirement	• Participating Load Agreement (PLA) • Participating Generator Agreement (PGA)	The Demand Response Attestation form (see EIM BPM Appendix C) shall be used to acknowledge EIM entity responsibilities when accounting for DR participating in EIM via load forecast adjustment
Interconnection Requirements *See the Resource Interconnection*	**ISO:** None; registration process. [See the DR User Guide for additional information] **UDC:** None, unless a behind-the-meter device is providing DR, then refer to Rule 21.	**ISO:** ○ ISO Interconnection Process ○ ISO New Resource Implementation (NRI) Process **UDC:** ○ Must abide by UDC interconnection application process for the purposes of ISO wholesale participation ○ Once UDC Interconnection approval is granted, resource	**ISO:** ○ ISO Interconnection Process ○ ISO New Resource Implementation (NRI) Process **UDC:** ○ Must abide by UDC interconnection application process for the purposes of ISO wholesale participation	N/A

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Guide webpage for additional information		enters ISO ***New Resource Implementation (NRI)*** process **Note* Requires alignment between distribution-level interconnection and the ISO NRI process*	○ Once UDC Interconnection approval is granted, resource enters ISO NRI process	

Resource Sufficiency Evaluation (RSE) implications	**PDR:**
	• Bids considered in real-time & day-ahead are used in RSE
	
	RDRR:
	• Real-time bids considered
	• Day-ahead bids considered
	  ○ Non-bid but shown are considered*
	
	*Pending EDAM rules
		Bids considered in day-ahead & real-time	Bids considered in day-ahead & real-time	• Reduces or increases entities' shown capacity needed to support load and pass RSE.
				  ○ *Required* to reduce load
				• When submitted, always considered in RSE, but may not be recognized in real-time market load forecast

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Summary of Bidding Requirements for Resources Providing System RA Capacity[1]

- **Note* The DERP model is ineligible to provide RA*
- Must-Offer Obligation (MOO):
    - 24 Hours a Day
    - IFM, RUC and RTM for all hours for all RA MW
    - Can be given non-binding RUC commitments if it is short start
- A PDR must bid under the MOO whenever the PDR has demand reduction availability. If the PDR is capable of reducing load 24 hours/day it must bid 24 hours/day. If it is only capable 14 hours/day (i.e. the business is only open 14 hours/day), then it must bid those 14 hours/day.[2]
    - Minimum DR MOO requirements: 4 hours per dispatch, 3 consecutive days of dispatch, and 24 hours per month of dispatch
- Bid economically – PDR is not subject to local market power mitigation; therefore, highly priced bids will not be mitigated by the ISO.

Summary of Bidding Requirements for Resources Providing Flexible RA Capacity[3]

There are three different types of Flexible RA Capacity, Base Ramping, Peak Ramping, and Super-Peak Ramping. A resource qualifies to provide Flexible RA Capacity in each Flexible Capacity Category for which it meets the qualifications set forth in ISO Tariff Sections 40.10.3.2, 40.10.3.3, and 40.10.3.4.

- **Note* DR is best suited to be a "Use-Limited – Super Peak Ramping resource" which requires:*
    - MOO:
        - May –September – 7:00 am -12:00pm
        - October – April – 3:00pm – 8:00 pm
    - Non-holiday weekdays
    - Minimum 3 hours at our EFC
    - At least one start per day
    - At least 5 dispatches per month during the 5 hour MOO window
        - Bid economically – PDR is not subject to local market power mitigation; therefore, highly priced bids will not be mitigated by the ISO.

[1] For additional information, please refer to the Reliability Requirements BPM, located on the BPM landing page
[2] For more information, please refer to Sections 7.1.1 and 7.1.2 of the Reliability Requirements BPM.
[3] For additional information, please refer to the Reliability Requirements BPM, located on the BPM landing page