BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	Rulemaking 13-09-011

NOTICE OF EX PARTE COMMUNICATION

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June 23, 2014

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NOTICE OF EX PARTE COMMUNICATION

Pursuant to Rule 8.4 of the California Public Utilities Commission's Rules of Practice and Procedure, the California Large Energy Consumers Association[1] (CLECA), hereby gives notice of the following ex parte communications.

On June 20, 2014, Barbara Barkovich, consultant to CLECA, met with Rachel Peterson, advisor to Commissioner Florio, and Carol Brown, Chief of Staff to President Peevey, regarding demand response. The meeting took place at the Commission from approximately 10:30 am to 11:20 am. Ms. Peterson requested a copy of Dr. Barkovich's summaries of three days of public workshops held on demand response matters in R.13-09-011 on June 9-11, 2014, which Dr. Barkovich provided to her; the summaries are attached to this ex parte. The meeting was initiated by CLECA to offer an opportunity for clarification of any matters included in the summaries.

Dr. Barkovich explained that confidential settlement negotiations were

[1] The California Large Energy Consumers Association is an organization of large, high load factor industrial electric customers of Southern California Edison Company and Pacific Gas and Electric Company. CLECA member companies are in the cement, steel, industrial gas, beverage, pipeline and mineral industries. CLECA has been an active participant in Commission regulatory proceedings and Commission Demand Response Programs since 1987.

ongoing and that she could only discuss parties' filed testimony and public statements made at the publicly-noticed workshops. Other than acknowledging their occurrence, Dr. Barkovich did not address the on-going settlement negotiations.

With both advisors, Dr. Barkovich addressed two issues that had arisen in the workshops. The first was the status of integration of utility demand response programs into the markets of the California Independent System Operator as discussed at the June 9 workshop. The second was the discussion at the June 10 and 11 workshops as to how the load forecast could or should be modified to take into account load modifying demand response as adopted by the Commission in D. 04-03-026. Dr. Barkovich explained the different perspectives of various parties and noted the need for engagement by parties on this issue at the California Energy Commission through the Demand Analysis Working Group or some other vehicle. Dr. Barkovich also informed the advisors that a formal workshop report would be served on July 24 with an opportunity for comments in the form of corrections.

Respectfully submitted,

Nora Sheriff

Counsel to the California Large Energy Consumers Association

June 23, 2014

DR Workshop 6-9-14

I did not write up the cost allocation discussion.

BUGs

4/2/14 Ruling, D11-10-003, KEMA study
ALJ questions

There is disagreement on applying the policy in D. 11-10-003.

*NRDC willing to talk about BUG for different DR programs with different intents.

PG&E: CPUC policy statement was with best of intentions. If lose DR as a result, could use even more fossil generation. Should study this.

Jurisdiction: TURN has not weighed in. Says Commission has authority if CPUC authorized $ for program. Can tie to participation if Commission uses DR as a preferred resource as opposed to reliability DR.

PG&E: DR is currently largely reliability resources and not used very much. Don't anticipate changed usage.

Mona: RICE-NESHAP has exemptions for emergency ISO or IOU requirements. This is in addition to state regulations. Generation owners have obligation to track and report use of RICE and prove onsite testing use for emergency purposes. EPA is contacting gen owners to assure compliance.

JCI: It makes sense to test units during DR events.

PG&E: if DR program is 3rd party using Rule 24, it allow 3rd parties to use retail load to participate in ISO markets, and tracking of BUG would not apply. CPUC has no role if it is not a utility program.

ED: Policy statement says CPUC-jurisdictional LSEs; they have same RA rules so would apply. Not clear if sold DR to SMUD.

Cost of Integration

PG&E: Corey Mayers presentation (I have notes but we have presentation in the record.)

SDG&E: Rafati presentation. He said SDG&E may have left out a few things since in process of integration. Said costs depend on outcome of bifurcation and program classification. Cited complexity of integration. Can use manual process for bidding in CBP. Only 500 customers. Would require automation for Summer

Saver with tens of thousands of customers. Third party enablement requires upgrade of IT, billing, CRM, middleware infrastructure. Cost $1.5-3 million. Business processes $600-750k. This could change once participate in the market. SDG&E will take some CBP into market by end of summer. 2014 partial CBP; 2015 full CBP, BIP integration, potential 3rd party; 2016 hope for full 3rd party integration.

SCE: 3 proceedings; TY 2015 GRC $5.8 million for market operations and supply for geographically dispatch, forecasting, bidding and dispatch. $5 million authorized in last DR case. There was money in 09-11 application that was unspent being used for DRP registration and customer registration. **Challenges: geographical dispatch at sub-LAP; pending regulatory filings, and waivers with ISO.

CAISO:Laundergan Oveview of costs-pretty much followed his powerpoint. Discussion: R Anderson Olivine pointed out there are size limitations for RIGs and ECNs.

Joint parties' presentation: They were pleased that don't have to have a RIG in ever sub-LAP. But they have concern about having to provide 1-minute interval data (more frequent than in other markets), telemetry within .2% accuracy, and telemetry requirements for A/S. Say if aggregate under 10 MW, increase performance risk by reducing size of aggregation and portfolio diversity and increase administrative costs. Minimum size needed to recover admin costs is over 10 MW. Re use of NOC: if can use NOC to transmit data, it would lower cost but they would have to break up the resources. They are not currently collecting 1-minute data for energy. Real-time data in network operation center (NOC) is not revenue quality meter data (RQMD) or settlement quality meter data (SQMD.) Don't get RQMD for 33 days. Re sub-LAP bidding, larger aggregation better especially for system resources. Higher costs mean less revenue and less to share with customers.

ALJ to panel: what is a reasonable range of costs? How to decrease costs? PG&E's proposal to decrease costs?

SDG&E: Did not include cost of including PDR and connecting to CAISO Demand Response System (DRS). Costs do not include forecasting load reductions.

**SCE: re request of waivers from CAISO: The one official waiver request was for no telemetery for PDRs over 10 MW. They also asked for registration simplification. They said PDRs would behave in a discrete fashion (i.e. fixed blocks of MW) and the ISO wanted incremental (ability to choose the amount it wants to dispatch). They did not ask to waive uninstructed energy for a discrete bid, fearing ISO would reject a bid that did not meet its parameters. They did not want ISO to kick out bids. Requested waiver early since in past had to submit

Resource Data Templates then register customers. Now ISO says register customers first and then request resource IDs and then RDTs. Expect no guidance on waivers from ISO until submit request.

ORA: why didn't PG&E, SDG&E ask for waivers?

**PG&E: our costs are not based on waivers. We are taking ISO tariff at face value. This is the reason the cost is so high.

**SDG&E: working with resources under 10 MW. No telemetry. Doing manual registration. May request waiver for discrete dispatch. Toe in water. Just energy and 3rd party data.

**SCE cost estimate is to take its entire portfolio into ISO as the portfolio *currently* exists. This is separate from $2.7 million for 3rd party DRP including CISRs.

**PG&E: Building capability to do everything to implement ISO tariff: bifurcate to integrate its own resources and those of 3rd parties. Includes ancillary services (A/S) for PG&E and 3rd parties. Including smart meter data.

**ISO: we are still learning in working with SCE.

**PG&E: our toe in the water cost is $3 million. We have been doing PDR the longest and have never asked for a single exemption, e.g. 5 minute interval data for A/S or real-time (RT) for residential customers. VEE data for non-interval bundled customers are still a cost. Need agreement on what parties we will bill and what the costs will be.

Goodin to Mona: Do your systems have RT data? Mona 5 min, not 1 min. To get 1 min data have to change equipment at every customer site. ISO: 1-min data from customer to DRP systems.

PG&E: KYZ is not telemetry.

Goodin: our standards are NOC to ISO. Laudergan: IOUs have AMI with 7-second connection feel from meter. Can this go to NOC?

Mona: our customers over 200 kW don't have AMI with this capability. Data at the meter is raw, not VEE'd. If went to NOC would have to be cleaned.

NOC aggregated data to ISO. How it is sourced is up to DRP. RIG talks to meter every minute. What type of information? Has to be instantaneous read, not KYZ.

R Anderson (Olivine): can average over a minute. De Backer (PG&E): equivalent to RQMD. Response: need special meter. IOU meters of 5 minutes.

Goodin says EnerNOC 1 min to 5 min. de Backer: not high enough quality. Shorter time, less accuracy. Laundergan: only update when threshold changes. Comverge: has systems for operational direction to track customers performance, but directionally accurate and not SQMD.

Ali (ISO): PJM, MISO operate under NERC BAL-002 but ISO operates under WECC BAL-002. There is summary doc on telemetery on ISO/RTO Council website. Says MISO BPM 26 appears to have telemetry requirement but Mona says only for regulation.

PG&E: we built our costs from the bottom up.

SCE: when we discuss what we can do, IT people ask: where does it say it, where is the BPM?

Need to take a step at a time to avoid spending too much $.

Goodin: bifurcation is in 2017.

*PG&E: we need firm business requirements but ISO says will keep changing.

Marcel: Should I be worried about $20 million in PG&E IT costs? Question re RIG requirement.

R Anderson (Olivine): PDR limits have not changed. 400 MW and 25 resources per RIG.

Marcel: A/C cycling?

A resource is an aggregation of resources, the level at which bids are made and settlement occurs, all within a sub-LAP.

Mona: Could have more than 25 resources around the state and more than one RIG.

RIG: Has protocols and verified by ISO but can be software. Cost in not a barrier.

Costs that can be barriers:
Aggregation of multiple assets to RIG
RIG to customers, not RIG to ISO
There are timing and metering requirements; not sure KYZ meets them
**IT infrastructure costs are HUGE to aggregate
*One solution: sample individual sites rather than metering at each site.

*ISO: don't' expect a lot of A/S. EnerNOC: A/S is a better value option than energy. 10-20% is A/S but expect to grow. In PJM 33% of synchronous reserves requirement is DR and rapidly growing under FERC Order 755.

Ali: cheap option validate DRPs and tracked in system.

PG&E: ISO validates location is not in another location. (ISO says this is a headache.)
PG&E: must assure load is under only 1 DRP. This is our headache.

*Ali: PDR telemetry section 14.1 mentions statistical sampling.

*PG&E: We would have to get permission, know how to sample, etc.

Comverge: All our residential DR settles using statistical sampling.

ISO to Mona: 10 MW load reduction is not cost-effective? Answer: resources are over 10 MW. How is communication done between IOU and DRP now? Mona: dispatched electronically by utility to DRP dispatch, it is a contracted amount-a block-done using an APX system.

ISO to IOUs: how much of this could be contracted out and competitively solicited?

PG&E: not fair question since we are building a foundation as opposed to contracting. Would change business requirement.

PG&E de Backer: The real issue on integration is 3rd parties into IOU systems. Not much advantage using 3rd party, especially enrollments.

PG&E Abreu: we contract out DR to aggregators; we use Olivine, APX. There systems to interface with customers that we have to do in-house. Total budget includes subcontracts. Will continue to use APX, EnerAct.

**The marginal dispatch requirement changes integration requirements – it is BIG! (PG&E, SCE)

**SCE: high cost is pulling meter data back on RT basis; meters are not set to do this. C&I customers have 15-minute data downloaded several times a day. Residential: 1-hour data.

Laundergan: HANs have 7-second data but need something in the house to talk to aggregator RIG. Would have to test to see if it works. ISO is considering working with IOUS on this. How long? 1-year study.

Mona: it is recent that utilities are starting to sync HAN with meter. The entire system meter to HAN to RIG has not been tested. We have to aggregate 7-second data by site.

PG&E: utility has meter with HAN capability. LBNL: have been working on getting 4 second data from meter and relaying that. PG&E: within premise it is the customer who controls. ED: I have a HAN device with 4-second data.

Goodin: want a tech working group to sort this out. To Mona: you say there is an issue with local dispatch. She says problematic and adds costs. He says ISO-NE is going to fully integrated DR in many zones and PJM wanted dispatch by ZIP code. Comverge: re ISO-NE, these rules and MOO are shrinking DR in ISO-NE. Re PJM-4 pre-defined sub-zones. PJM asked for unlimited subzones and FERC said no. **The more you automate the less flexibility you have.

Comverge: when PJM calls dispatch, it gives resource IDs to DRPs.

Mona: There is a geographical locational dispatch issue due to mix of customers. Need 15-20 MW of C&I load within sub-LAP. Wouldn't take all of them. Will pick best performers. Wants flexibility to do large or small e.g. system dispatch like FRAC-MOO; if dispatch multiple locations e.g. multiple sub-LAPs with DLAP, why not DLAP wide?

**R Anderson (Olivine): you haven't mentioned the LSE issue-can't co-mingle customers of different LSEs within the PDR. Bigger risk: # MW by LSE in sub-LAP. We have 15 LSEs. Requirement in ISO tariff, need to invoke stakeholder process at ISO to change tariff. (Reason for concern is need to have at least 100 kW per sub-LAP per LSE.)

Comverge: recently eliminated LSE requirement in capacity market somewhere. (missed it)

SCE: wanted to do multiple registrations by LSE; need to re-engage.

R Anderson: the challenge is the default load adjustment (DLA).

PG&E: can renegotiate contracts for some aspects of RT metering or PG&E can install its own metering equipment at customer site for sampling as MDMA. This cost is not included in PG&E forecast.

PG&E: know 10 MW telemetry requirement is a WECC one, but ISO could raise it with WECC.

Under Rule 24, telemetry is not IOU requirement unless the IOU is the DRP. IOUs are not spending money on telemetry and RT metering for Rule 24. A little spent to prepare for A/S over 10 MW.

Summary of DR Workshop 6-10-14 (morning)

Load Modifying (LM) vs. Supply Resource (SR)

LM-not an RA resource and no MOO
SR-dispatchable, meets RA requirements, integrated in ISO market, required to be bid into ISO markets and dispatched, MOO

ISO position is that not all DR has to be SR; maybe minority

EDF concern about how RA "credit" would be determined for LM

SCE-having a supply resource that can be traded is not same as LM; if resource is dispatchable and is seen as LM, it should have RA credit; RA capacity that can be traded

ISO: LM DR is not tradable

Mona: today we have to be dispatchable by IOU and the DR is required to meet RA; today that is fungible RA capacity; moving forward, you are talking about this DR not being fungible, not an RA resource; that represents a change in its value

ISO: in 2017, to get RA resource credit, your programs would have to bid into ISO markets

PG&E: today all dispatchable DR counts toward meeting RA requirement. In past, there were times when DR was subtracted from load to reduce the RA requirement using the LIP (load impact protocols). Under bifurcation, changes are proposed. PG&E is OK with some DR meeting RA and some reducing load forecast and thus RA requirement; but ISO has strong view that anything that counts for RA has to be bid into their markets like generation. We think LM DR should have value for reducing the RA requirement.

ALJ: either way the IOU can use DR to meet or reduce RA requirement? Yes. But the rules are not in place today.

Sierra Club: the essential debate is what goes to the ISO and what does not. Can have LM DR that is dispatchable but not visible to the ISO. The issue is load reduction.

EDF: RA credit could be less for LM DR than SR DR; thinks it should have commensurate or greater value.

SCE: if dispatchable and if can forecast how LM will modify load shape, why does ISO have issue? Our critical peak pricing (CPP) is dispatchable. When include in forecast, ISO says have to assume it will always be called on-peak. In the past, we just took it off the peak.

ISO: there can be programs dispatchable but not by ISO. SCE says when it calls BIP it modifies the load. ISO says currently every hour, the impact of DR is added back in by the CEC, since DR is currently treated as a resource. That will change with bifurcation.

TURN: RA is a one-year construct. DR does not replace powerplants. If we are going to pay DR like new generation, it has to eliminate a powerplant.

PG&E: April LIP goes into RA and LTPP. To avoid new generation, DR has to go into LTPP. Historically, dispatchable DR was treated as a resource and had to be added back into the load forecast. If we make changes, have to change the way we do LTPP. It appears in IEPR the CEC did not add back in two programs, CPP and peak day pricing (PDP).

PG&E: there is a problem with CEC method now and we have to fix it. There has to be value either way for LM DR. It has to be available at peak but it does not need to be dispatched at peak. It has to be available in the hours in which it is needed so it can be dispatched. It cannot be withheld. Need to go back and look at RA and LTPP rules via the DAWG (Demand Analysis Working Group).

ISO: how can LM DR count in full when it is not dispatched at peak?

PG&E: We have an AMP program at 100 MW. Today it counts at 100 MW. In past it would have lowered the RA requirement by 100 MW. In future, if it is not bid into ISO markets it will not meet RA requirement under bifurcation. The IOU will dispatch it and it will be available all required hours. If the ISO needs to call it, it will be fully available to the ISO on reliability and to the IOU on price. When the peak day comes why might we not dispatch it? **Because we have lower cost resources to dispatch. It should count if it is available at peak. Otherwise, the IOU will pay AMP that is not counted to meet or change load. (SS DR meets load, LM DR reduces load)

SDG&E: utility concern: when forecast, when you weather normalize, will you take into account that DR wasn't needed in cool year but will be used in a hot year?

Mona: agrees with SCE. Resources provide operational flexibility for IOUs; if insist it has to operate at system peak, you can't predict that perfectly; if that is the only criterion, you will devalue the resource.

ISO: the choice of when to dispatch this is the reason you have an ISO. Why not include it in the ISO market?

*PG&E: ISO can dispatch things a little more precisely than IOUs but 1) it costs a lot to implement, 2) we can't bid the DR in if the customer's LSE won't allow it 3) we can't always meet 100 kW requirement by sub-LAP and LSE.

ISO: you are suggesting changing forecasting for RA.

SDG&E: DAWG is starting to address this issue in the DR subgroup. CEC needs to be involved.

CEC: should be addressed in DAWG. This is on its agenda, along with forecasting by sub-LAP. If CPUC continues with bifurcation, in order to get value for DR, there has to be a change in how we do the forecasting.

SCE: (ironic) if put LM dispatchable resource into our load bid, can you assure it will be called on peak?

EDF: LM DR clearly has value to IOUs; wants clear value linkages

R Anderson (Olivine): one of real challenges is programs that cannot all be bid in; it will be hard if some part of a given program can be bid in and another part cannot, e.g. two portfolios in CBP, 1) over 100 kW can be bid in and 2) less than 100 kW cannot. This will also be hard to forecast.

Mona: re Goodin, if 100 MW LM DR resource is not fully dispatched on peak, you are saying that it should not fully count. But there are other resources that don't supply their full output on-peak.

CEC: we are talking about DR here, which is not directly equivalent to generation. A reason you don't want to fully dispatch is customer fatigue. Customers have opportunity costs.

CLECA: C/E DR is a top loading order resource. The Commission wants to grow DR. Under the bifurcation rules, there is a risk that LM DR will have reduced value. Need to make changes in RA carefully and deliberately.

PG&E: We have called CPP many days in a row without customer fatigue.

CEC: may be true for amount it is dispatched right now; not sure true if dispatched a lot more to affect the load shape.

ISO: loading order is to avoid building fossil generation. To really avoid, have to reduce peaks and ramps.

PG&E: the RA and LTPP cases are essential to valuation of DR. This proceeding must provide clear guidance to RA and LTPP and CEC.

SCE: ISO proposal for LM DR holds DR to a different standard. Says it has to be there on-peak.

ISO says for LM DR, IOU has discretion to use or not use. It is now up to IOU to use or won't reduce peak.

If there are market dispatches on price, there are no guarantees will hit the peak.

ISO: MOO obligation is more onerous.

EDF supports PG&E re need for guidance in this proceeding for RA and LTPP. ISO agrees.

TURN: struck by R. Anderson comment about 3rd category of DR. Asks ISO: focus on coincident peak but new generation construction is driven by local demand or flexible need. How does that relate to coincident peak?

SDG&E: a key issue for SDG&E is distribution loading. How do distribution benefits fit into RA counting when used for local problems? ISO: via avoided T&D value. SDG&E: where and how to tackle that issue-focus here is RA and system. Where? Which proceeding? EDF agrees is important.

SCE also talked about local peaks. Preferred resources pilot. Local reliability is an important issue.

Sierra Club: we were criticized by ISO for 3rd category of DR. It is appropriate to have resources reserved by IOUs. Acknowledge and value.

PG&E: We are concerned about distribution instability and want to be able to use DR for this.

ISO: may be a resource with two different operators, distribution and grid.

SCE; we are talking with the ISO about sharing resources and have a first cut solution.

MCE: we want to do DR. Whose load gets modified? (not sure I got this right, but I think he meant whose load shape is modified?)

SDG&E: how do you address valuation for off-setting overgeneration? This is not addressed in cost-effectiveness (C/E) protocols.

ALJ: workshops for the next two days. Must still get a decision out by EOY on Phases 2 and 3. Original schedule: submittal by end of July. 90 days for ALJ to write and get through process, mail to parties end of October for first December Commission meeting.

Other constraints. IOUs must file their applications for 2017-2019 in November 2015. Need guidance document May 2015 or, preferred, March.

Must Offer Obligation (MOO)

Mona: SS DR bid in and has MOO. FRAC-MOO has MOO. System DR does not currently have a MOO. Is MOO required? Currently, AMP available to utility during certain times and at strike price. PJM does not have MOO; has availability windows. Paid higher of strike price or LMP. MOO includes obligation to bid into day ahead (DA) and real-time (RT) markets. How frequently will resource be dispatched based on LMP? Proposes alternative to MOO. ISO would have call option in certain time frames with certain notice requirement.

ISO: MOO for use-limited resources is an as-available MOO, at least for RDRR. Notification time: If resource is not picked up in RUC and has a notification time over 5 hours, would have no RT obligation. Why is this onerous?

Mona: How would as-available DR bidding into ISO market meet RA requirements?

ISO: 4 hours for 3 consecutive days, 24 hours/month, to meet RA.

TURN raises concern over potential incentive for high DR strike price.

ISO: there is no price requirement for DR. For system RA, requirement is must self-schedule or MOO. For flexibility, MOO requires economic bids. There is nothing in market power mitigation to mitigate bids for PDR.

Mona: 4 hours for 3 consecutive days, 24 hours, are *availability* requirements, not operational.

ISO: if DR resource is available, it has met its obligation for RA.

Mona: there are two aspects added. 4 hours for 3 consecutive days is designed for peak loads. 24 hours a month availability was added a few years ago. Does the first satisfy the second?

ISO has considered 24 hours to be availability.

SCE: challenges notice of a strike price. Customers have an opportunity cost which increases the number of times DR is called. A price cap is relevant in a market. Customers don't show their interest at different potential strike prices.

ISO: for 2017, DRP needs to discuss this with customers. DRP can have more customers than it needs and construct a resource and pay for the amount of DR provided. Does MOO accommodate this?

SCE:What if I sign up a customer who wants to be dispatched 4 times a year?

ISO: have to offer what is available.

ISO: Use-limited resource has to submit a supply plan so ISO knows when it can be dispatched. Issue: what is a valid use plan? For generation, environmental and operational issues are valid and contract and economic issues are not valid. Might be considered for DR. How does CPUC define availability for DR?

Mona: Availability is one aspect. The other is how availability translates into a MOO. If include use limitations into supply plan, how does that translate into meet peaking requirements? Currently, June through Sept, x hours a day, and maximum and minimum requirements. Concern that expectation that integration means dispatch and clearing at bid price. Don't expect a lot of DR at current market prices.

ISO: AMP contracts may not fit into ISO view of the future. It is an open question if there are use limits. When establish a DR contract, establish what it can provide, equivalent to a P max. When forecast DR availability the next day, might forecast less.

PG&E: under current RA rules, all RA resources must be available 2-6 pm, all summer non-holiday weekdays. Operational requirement is 3 consecutive days, 4 hours a day, up to 24 hours.

ISO says policy for use-limited resources in future is in RSI, where considering explicit MOO for use-limited resources. If don't have strict MOO (we will put in a bid for you if generation), how to have availability incentive? How to move DR to be more available, similar to other use-limited resources? SCP is outage based. Moving to bid based.

SCE: If resource is available to be bid into markets, it will be bid. SCE monitors the use of a resource since it has a use limitation. For example, if it can be used a max of 100 hours, choose 100 most valuable hours. Determine opportunity cost and bid above opportunity cost.

PG&E: if resource is in day-ahead market and not taken, will it roll over to real time market?

ISO: rely on ISO master file. If long-start, not required in RT.

PG&E: what if contract says day-ahead only?

ISO: identify operational restrictions on DR to extent they are in master file, not sure how would be determined

PG&E: process will dictate value; want clarity sooner than later

ISO: To be determined in RSI

PG&E: this is complication and is a reason for concern about SS DR. Another concern, for LM DR, counting toward RA. If it is available, it should count. The ISO says no.

R. Anderson (Olivine): requirement for RT market is huge issue for ISO market integration. RT market works very differently from day head. Would resource have same value if not in real-time market?

Day-ahead market rarely clears at $1000/MWh. RT market does more often with congestion. Thus there is less value if not in RT market.

PG&E: LM DR used on peak vs. available on peak. How would ISO process take into account how to deploy resource so that you don't use it all up too soon?

ISO: importance of the use plan. SCE can update the use plan every month. This issue is addressed in ISO process called Commitment Cost Enhancement.

ED: Current CPUC decision for use-limited resources includes DR but never enforced. MOO does not mean must submit bids in every market. There is no CPUC MOO requirement. Any MOO requirement would be implemented in 2017.

Jt Parties: there is a lack of clear understanding of ISO rules past and future.

GOALS

SCE: should re-visit goals and make them needs-based. A market potential study would be useful. Should focus on local capacity need. Impacts value. Targets should be established like EE more on a portfolio basis. Recognize customer limits and avoid migration of customers from one program to another.

Sierra Club: Goal should be all C/E DR. To know what this means, consider avoided capacity costs. Goal should be to remove all barriers. Consumer-friendly programs. Suggests Commission look at program design. Notes cap on reliability-based DR is "wildly low". Should tie avoided capacity cost to value, including bid cap in DRAM.

EDF: not needs-based. Opportunity-based approach, especially for LM DR. Optimize by location, at nodal level.

ORA disagrees. Thinks 2% goal is good. Likes need-based goals, rather than insurance-based.

TURN: we have a cost-effectiveness (C/E) protocol and we are maxed out on C/E.

Clean Coalition: need goals, cites storage case. Targets and C/E.

CLECA: maintain reliability-based DR.

Mona: LTPP decision identified need and resource type identified as meeting those needs. Re C/E: we have a methodology that is not keeping pace with changes in role of DR. Look at alternatives to C/E, especially if IOU is doing RFO or DRAM. For most procurement targets, if LSE finds that there are no C/E options, they should be able to demonstrate this to the Commission.

PG&E should continue to grow DR, maximize C/E. C/E depends on value and cost. Need to reduce risk and cost and increase value with new products like flexibility and overgeneration.

ORA: if RA is cheaper than DR, why buy DR? (least-cost)

SCE: likes all-source RFO. A reason to avoid fixed procurement targets for DR. One size does not fit all. Need a portfolio of DR capability: price responsive, reliability DR (option type value-value February 6, 2014), all-source competitive RFO. Manage in a C/E manner but don't dispatch all of them all of the time. May want to look at growing reliability–based DR.

PG&E: Responds to TURN. If DR payment is over current RA price? Issue is how does DR fit into LTPP to displace new generation. New gen needs long-term contract. For DR, don't need this. Need to have a plan for 10 years, but can procure periodically to avoid generation and maintain for 10 years. Allows changes and adjustments.

SCE: Why do we always define C/E in terms of proxies? Prefer a needs-based framework. C/E is cheapest way to meet a specific need. What is the problem you are trying to solve? What problem is 5% price-responsive DR goal trying to solve? GHG? Renewable flexibility?

Eliz. Dorman: agrees with SCE. PU Code 454.5 lists criteria for IOU portfolios. Doesn't say least-cost.

EDF: the system is for customers.

Mona: DR has different capability depending on what you use it for. 2% cap on reliability DR but have contingency reserve value.

MCE: want to offer DR, as goal, want to enable all LSEs to do DR. Fixed goals or obligations create problems for LSEs: cost allocation and jurisdiction.

TURN: likes needs-based goals. Commission hasn't addressed role of DR. Concern about LMP for retail. Can you change load curve in another way?

EDF: we are not looking at rates imposed on customers. We are looking for opportunities.

Jt. Parties: re lack of long term contracts, DR is about customers who have to be engaged. Changing contract terms or requirements every year undermines commitment from customers.

PG&E: Seams issues with LTPP, RA, rate design.

EDF: LM DR means impact on tariffs.

6-10-14 DR Workshop Notes from afternoon

DRAM/Cost-effectiveness

ED: will apply cost-effectiveness (C/E) to each DR contract in DRAM. If a bid is less than the cost cap and is C/E, goes to CPUC for approval. If it is less than the cost cap but is not cost-effective under the protocol, it is not approved. Whichever is lower prevails. (?)

TURN supports this; expects prices to be close to avoided cost.

ED: will soon release new C/E protocols. Will largely apply to LM DR. Re SS DR: you bid, we will look at bids, at DR product and establish an avoided cost benchmark; we will calculate the avoided cost of the DR product. For each DR product, have to take characteristics into account through the adjustment factors. Haven't developed an avoided cost for flexible DR yet, but there is a discussion in the draft and comments are requested. Re overgeneration: In theory, should be able to predict periods of negative prices.

Sierra Club: why, if bid is C/E at avoided cost, do you have to have a bid cap?

ED: DRAM is competitive. Could use C/E as ultimate cap. But why wouldn't everyone bid at the cap? Depends on the size of the market and how much competition there is. The cap was to drive prices down. We interpret statute to say any capacity and energy must be cost-effective.

ISO: re overgeneration, look at C/E from retail or wholesale prices? You are asking load to move up and down.

ED: model based on past trends; at negative prices we show no net benefit.

SCE: Model builds a price duration curve; if have the right duration curve and negative prices, could model, but our DR programs are not built to do this.

ED: C/E protocols are primarily for LM DR.

SCE: do protocols deal with local capacity? ED: Maybe.

SDG&E: DRAM has system, local, and flexible RA. Does C/E protocol address?

ED: See if it does when you look at the draft protocol.

CLECA: re DRAM cost cap. If cost cap is weighed average, will it knock out all bids that are higher? Can have an auction where there are two large low bids and many high bids. If trying to incent and grow DR, will it be a good idea to ratchet down the price?

ED: We re not proposing to ratchet down prices.

ED: Bid mitigation to kick out bids that are “disproportionately high”. Would allow utility to reject bids if suspect market manipulation. If continue DRAM, should standardize bid mitigation.

Sierra Club: in RAM, the concern was unreasonably low bids and the solution was viability criteria, including demonstration and penalties. There were also a lot of participants.

ED: concern about DR bidding into ISO at offer cap.

ISO: PDR and RDRR don’t have local market power mitigation.

ALJ: role of utility is an issue. Create incentives for 3rd party DRPs to take customers from IOUs.

ED is now saying we propose separate bid cap for each type of RA. ED wants one auction, not 3 separate auctions, but each (system, local, flex) would have its own bid cap.

ISO: are local and flexible subsets of system or discrete? In RA, unbundling flexibility from system RA is an issue.

SCE: Let’s discuss the 3 products. Construct is the IOU buying an RA tag, not capturing market revenues that DRPs get from bidding into the ISO markets. If cost allocation proposal is upheld, would spread RA value of tags across all LSEs. Why not just let the market work and let customers or 3rd parties do it?

ED: there is no CCM and there are insufficient revenues from ISO markets. Use ISOs for additional revenue stream.

SCE: ESPs have RA requirements. Can’t you have a structure where ESPs can buy from 3rd parties?

There is expectation that generators are not willing to invest in 30-year assets without missing money. Is this the same issue with DR? What is the utility role?

ED: DRAM is for 3rd parties. Can use bundled customers under Rule 24. This is outside IOU programs.

TURN: cost cap in DRAM is based on bids. Would you select on lower $/kW-year price regardless of other features? Beyond local, flex, system? How would you reflect availability?

ED: depends on how you do weighted average calculations, could be based on characteristics as reflected in C/E method.

Jt Parties: Characteristics for RA qualification should factor in, some of which are not yet determined. Have to do at least the minimum.

6-11-14 DR Workshop Notes

Further DRAM Discussion

Issue of emergency DR in DRAM. ED proposal would include emergency DR. It would not increase emergency DR to over 2% of coincident peak load.

PG&E: Would provision of emergency DR be through DRAM contracts?

CLECA: The bridge funding decision says no changes to existing programs, so not before 2017. Do not transition. Emergency DR is very important. Customers need to be there. BIP is integrated into ISO markets as RDRR, or at least as soon as IOUs implement.

ED: reason emergency DR is in DRAM is that our proposal is similar to other capacity markets.

CLECA: but they don't have a 2% limit. You don't want to risk what you have. PG&E's BIP is not fully subscribed at 2%. SCE's is. Don't force customers in S Cal to have to change to DRAM. If want to do pilot with DRAM for emergency DR, consider unsubscribed PG&E MW.

SCE: if we don't have increase in allowed emergency DR over 2%, using DRAM will just churn existing DR. 2% should be an issue for goals and needs.

Joint DR Parties: why should other DR programs have to go through paradigm shift and not RDRR? Note BIP is considered to provide some contingency reserves benefits. Want DR to provide multiple services. Don't know how to value vs. others. How to test value of BIP vs. others?

EDF: wants new opportunities for DR. Questions 2% figure.

PG&E: BIP is very different. It is callable 24 hours/day, 7 days/week, 365 days a year. You pay a different price for something like that. It also has severe penalties.

PG&E: re DRAM, could be one procurement method among others. Also need standardized products. If DRAM is opportunity to get DR into the market, remember that BIP does not bid energy into the ISO's markets. Also, remember that BIP is a statewide program. How would utility-specific DRAM accommodate this?

ED: DRAM rules would be the same for each IOU. All bids have to meet RA criteria. DRAM is for RA; it is outside traditional DR structure. IOUs would get RA tags. DRAM is a wholesale procurement program.

CLECA: How would a utility structure a program budget around it? You don't know the product or the price.

PG&E: there is a minimum requirement for RA. You don't know what else you will get.

CLECA: pilot price-responsive DR in DRAM.

Joint Parties: It is no different from any other procurement.

TURN: re what are you getting in DRAM? There will be bids with different attributes but IOUs can specify attributes they want, including BIP characteristics. TURN does not object to a separate DRAM for reliability and a separate cost cap in DRAM. Mentions usefulness for distribution-level reliability. Mentions SLIC process development.

For BIP, issue of providing local as well as system reliability, how to value?

PG&E: if want something that is always there, want a BIP. IOUs could develop a product for DRAM. If everyone who bids runs the E3 calculator, they will bid close to the bid cap and bids will be similar.

What level of reliability does the state want and what level of risk? Emergency DR is different from price-responsive DR.

Calpine: If what is being procured in DRAM is RA tags, value stream with other operational characteristics would be identified elsewhere.

ED: DRAM is for price-responsive DR, not for programs that already exist. Idea was to transition some to competitive market.

Joint Parties: Local RA is fungible with local flexible RA is fungible with flexible RA. Type of RA tag is important.

MCP vs. Pay-as-Bid.

ED: Reason for pay-as-bid vs. market-clearing price (MCP) is MCP is used in FERC jurisdictional RTOs/ISOs. Concern using MCP would be construed as setting wholesale prices. Also Section 454.5 requires procurement at least cost. ERCOT transitioned from pay-as-bid to MCP only when had enough experience with pay-as-bid to be comfortable. ED is not proposing to change to MCP.

SDG&E: do state processes influence feds? How is this jurisdictional?

ED: It is consistent with other RFOs to pay as bid.

Jt. Parties: Should use MCP. During the first year you have to include fixed costs. In later years, profit comes from being inframarginal. Does not agree that pay-as-bid is least cost. Why pay different prices for standard products?

ED: differences in bids would be captured in the ISO market use plan and be picked up in payments by ISO for energy and A/S.

Will parties bid to cost cap? Will this lead to gaming?

Clean Coalition: cost cap violates the loading order. Means won't take all cost-effective DR.

ED: could leave C/E DR on table or could have opposite if eliminate cost cap, have just C/E protocol and everyone would bid at that level. PG&E agrees.

Calpine: within a bucket there might be differences in DR bidding into DRAM. DR RA tags would emerge. What differences between bids would you consider when ranking in DRAM?

ED: 1. Fulfillment of utility RA obligation (system, local, flex), 2. Price. If have separate buckets, haven't proposed anything other than price.

Calpine: if procure standard tags, when is C/E method (e.g. A factors) relevant? If IOUs buy tags, they are not buying right to dispatch.

SDG&E: wholesale process; cost caps; maximize procurement of C/E DR; why don't we just have a cost cap based on C/E? We already do wholesale procurement through all-source RFOs. Why do DRAM separately?

In all-source, there are issues about how to compare.

ORA: support DRAM with weighted average cost cap with additional cap at C/E.

Current goal for DR is 5% of peak load in LTPP L&R tables. ED goal for DRAM goes from 2.5% to 5% in a few years. Need to translate into IOU procurement obligation for different RAs. Should be allocated to IOUs on pro-rata basis but each starts from a different place.

SDG&E: shouldn't the share depend on what is C/E? Each utility starts from a different place.

ED: start with EAP. Wanted a MW number. Utility not required to procure in excess of cost cap or C/E.

Does this include load impacts from dynamic pricing? That would affect load shape and MW from goal.

PG&E: 5% shouldn't just be from DRAM; it should encompass all DR. DRAM is just a procedure to bid into the ISO. 5% just for that is far from overall DR. PG&E doesn't object to a MW amount, but has concern about the large goal in the ED proposal just for DRAM.

SCE: goal for DRAM is a subset of overall DR goal.

ORA: Goals should consider past performance. Should not be too expensive; could start from what exists now. SCE said goal should be based on need and include locational DR.

EDF: What do you do if you are not near a goal? Need tracking mechanism; should not be need-based, should be value-based.

Jt. Parties: define "need". Is it incremental, e.g. to fill a gap? Should also consider whether we have maximized the use of DR for flexibility. If we don't have enough DR, what are the barriers?

SCE says should develop DR potential study outline.

Location is important for goals.

Issue of penalties under wholesale market vs. DRAM. ED: DRAM proposed penalties/derates are from AMP contract. Are they appropriate for DRAM?

Jt. Parties: In purchasing RA, if generator does not perform, there are penalties in contracts. Don't need separate penalties. Using AMP structure would double the penalties.

Local DR and RA

Questions to ISO (Millar): CPUC requires, if you can call program by local capacity area (LCA), can count for local RA. It appears that ISO has additional requirements, e.g. bidding into ISO markets? Meeting 30-minute requirement?

ISO (Goodin): ISO testimony is not based on how it is done today but is for 2017.

Millar: in looking at rebuttal, people inferred things we didn't intend or agree with. My role is planning; I am optimistic we can count on non-conventional resources for TPP to mitigate or defer new transmission needs. We want this to work. Re bifurcation, we see a role for forecastable, repeatable LM DR that the CEC can and will include in load forecasts. How CEC takes into account variability, etc., is their lead issue but because forecast is used for planning, we have to be sure we can meet our obligations under mandatory reliability standards. Re supply-side DR, issue came to head in 2012. Some level of DR that would respond to dispatch has been attributed to LCAs. Those LCAs had enough system RA that the ISO didn't have to use DR for local RA. After SONGS outage, we had to look at all DR programs to see what met operational requirements to count for contingency planning. Key requirement is that after losing a transmission line, operators have 30 minutes to reposition for the next contingency. We need to know what can be available in 30 minutes. We are looking to fully automate through Enhanced Contingency Modeling initiative.

When we do transmission planning, we have to take contingencies into account; we can decide to not approve new transmission if we can count on DR. In 2012, none of the programs met the operational characteristics to meet local, day-to-day transmission operational needs.

Confusion/disagreement: dispatching DR resources not visible to ISO; not clear how CEC would include in forecasting or how ISO would use for contingencies.

EDF: ISO acknowledges LM DR has value but then you argue should not count for RA but should be in the forecast; this is passive and implies that SS DR is more valuable. Importance of utility needs at distribution level that can reduce loading on distribution and also on system.

Millar: can't address incentives for LM DR to show up and reduce need, but it is not a resource. The value chain to appear vs. generation. If a resource is acquired first for local distribution and second for non-local or local transmission (e.g. 230 kV), not impossible but ISO needs the visibility and ability to dispatch as needed.

EDF: leave to forecasting which does not value it.

SCE: Commission must provide appropriate goals and valuation for that.

SDG&E: valuation is through CEC forecast but ISO says it can change or discount the forecast. How do we deal with coordination here?

ISO: Question of what ISO might modify

Millar: There is a theoretical possibility that, if the ISO found a gap, it would have to do something but doesn't expect it. With mandatory NERC standards, we can't blame someone else for the forecast used. When we meet standards, we pick the forecast we use. Process alignment work to agree on this. We have a federal obligation to fix if something is wrong but is not a common practice.

ISO: after Padilla hearing on infrastructure planning and data-developed process alignment. Mapped TPP, IEPR, LTPP. Staffs will work Sept Nov each year on assumptions and scenarios for TPP and LTPP. In December, ALJ issues draft and later adopts them. Form basis for inputs into TPP and LTPP. ISO has brought to the attention of DAWG to focus on how LM DR will be factored into IEPR. When?? Have not announced any further steps on DR working group of DAWG. Intention is to affect 2015 IEPR. Draft in fall 2015.

Sierra Club: have standards for DR to count for local reliability been articulated?

Millar: Resources are being counted for local reliability right now that may not be effective. To this point, those resources have not been used for day-to-day operation but for contingencies so we have continued to reinforce the system to meet single and double contingencies. If DR can't be used for TPP, move on.

Sierra Club: no clear requirements for DR to meet for local reliability

Millar: In Track 4 of LTPP, some programs were close; dispatchable within 30 minutes; but insufficient time for dispatch communications. For LTPP: these were so close, should be able to rely on these programs in 10 years, so they should be modified. Working with IOUs who are working on RFOs, so they can take these into account for procurement. (editorial comment: not transparent)

Jt. Parties: issue of what it takes to qualify for local reliability was NOT resolved in LTPP. CPUC defined local RA requirement but it didn't meet ISO requirements.

Goodin: System RA requirement is for 4 hours per day, 3 consecutive days, 24 hours/month for energy. That does not change. For local area, may need something different.

Jt. Parties: We do that, but ISO says they don't count to avoid generation in local areas.

Goodin: Idea that DR is held to different standards than generation; in theory, if have DR with day-ahead start, would have to be used more (Millar testimony); reality is need for fast response.

Millar: if operators look ahead, can dispatch a generator at minimum load via exceptional dispatch to be available.

Jt. Parties: these DR programs have moved on since 2012. If requirement is vague or keeps changing, it hurts DR; need clear instruction from ISO and a commitment.

Millar: talking to IOUs where long-term procurement is happening concern. A lot of analysis to use DR resource for new purposes. Don't feel we have been instantly changing. (transparency?)

Olivine: gap between operational planning (30 minutes); if use real-time dispatch, have 2 ½ minutes.

ORA: how to get the ISO to believe the DR forecast? Is it to have ISO control? Says utility dispatch is unreliable.

PG&E: ISO has NERC standards including 30-minute requirement. Need to check resource availability and use limitations. Check the bids in the system. Know minimum run time. Has to be dispatched within 30 minutes.

Millar: doesn't have to be available constantly. Requirement is there all the time but preference (?) for next contingency could vary. Looking at load curves for all 4 seasons.

Sierra Club: when will you provide a real definition?

Millar: in 2014-2015 TPP.

Clean Coalition: saw straw proposal Sept. 2013, then went straight from that to incorporation in TPP without any stakeholder process. When will we have an opportunity for more stakeholder process?

SCE: we would like more ISO engagement in our preferred resources pilot.

Millar: straw proposal started as academic exercise, then SONGS permanent closure happened.

AFTERNOON

Chris Kavalec CEC appears for a little while.

PG&E discusses how DR was taken off the top of the load forecast in the past; recently counted as supply resource to meet RA requirement. Have heard dynamic pricing not added back into forecast. Treat all as supply? In future, with bifurcation, supply DR as resource but LM to adjust load forecast.

Kavalec: In last forecast, DR taken off peak included non-event based (TOU) and dynamic pricing—subtracted from peak demand forecast based on LIP numbers. Event-based DR is added back into load, subtract out non-event based. DAWG has created a sub-group for DR. Next meeting in early July. Service list to Chris Ann Dickerson to notify interested parties.

Jt. Parties: not all event-based DR is being reflected on supply side in ISO TPP. Adjustments are to historical data, not forecast. Doesn't come out at the same place. Only count resources that ISO thinks will…

CEC has price elasticities for load but different from pricing programs.

How long does it take for a new LM DR program or a change in an LM DR program to show up in the forecast? If new non-event program in 2016, when would that be reflected in forecast for RA?

CEC Kavalec: last forecast was for 2013-2015. New program expected in 2016 and funded? If funded, would be included in forecast. Next forecast is 2015. An event-based pricing program would be fully reflected and subtracted from the forecast.

Goodin: In 2016, it is already in the baseline.

SDG&E: If it is a 100 MW program that isn't called because it is a cool year, we disagree with the ISO approach. How do you incorporate weather normalization?

CEC: Would be dealt with in LIP.

ISO: how about roll-out of TOU for small and medium C&I customers?

Goodin: effect of EE-varies with temperature. How do you reflect?

CEC: shows up in weather normalization for EE and dynamic pricing in base year.

PG&E: LIP are weather-normalized.

Jt. Parties: CEC has not addressed the proposed new paradigm

CEC: non-event handled one way today and event-based is handled differently.

Jt. Parties: in future, LM could be event or non-event. Will CEC maintain event-based vs. non-event based in future? Or will bifurcation result in changes?

CEC: In new paradigm, will still have event and non-event; would be handled like event-based pricing.

SDG&E: if undercount LM DR, it gets less value and utilities have to procure make-up RA.

TURN: How does sub-LAP relate to the LCAs?

Millar: haven't said all resources have to move into ISO market. LM DR that can be taken into account in forecast and reduce RA requirement. However, forecastable, repeatable DR qualifiers apply; if we can't track…Sounded like a 3rd category with dispatchable programs by IOU for parameters unknown to the ISO and use-limited.

PG&E: A/C cycling, one trigger is ISO can dispatch. We provide daily spreadsheet by sub-LAP and hour to the ISO. It is dispatchable, predictable, and forecastable.

ISO: we use in emergencies, not for conventional repositioning after an outcome. Operators don't know how much is available in the next hour.

PG&E: We notify the ISO of dispatch.

ISO: not always and too complicated in context of automated resources. Use spreadsheets for day ahead RUC and when there are extreme events but not for daily outage management. To automate, have to submit bid.

LM DR? Only through forecasting or through load bid? What about CAISO Forecast of CAISO Demand (CFCD)?

ISO: CFCD not adjusted for a running day-ahead market because would affect operating reserves. Only for residual unit commitment (RUC) and short-term unit commitment (STUC).

ISO: utility-controlled supply side. LM gets RA value through adjustment to base load curve. LSE should incorporate DR in load bid in integrated forward market (IFM). Will have supply demand balance. Does not affect A/S procurement, which is based on CFCD. In real-time, if there is a load drop, the ISO will see it by looking at actual demand in the system (situational awareness), and it will affect RTUC.

Jt. Parties: DR qualifies as local resources. N-1-1 is a very low probability event per the LTPP. Want to have DR in the markets on a regular basis. This is not consistent with a contingency event.

Millar: when dispatch the system, look at first level of constraints to deal with a contingency-exceptional dispatch. Cites contingency modeling enhancement to include in dispatch. Having resources in market all the time would be more efficient, i.e. year in and year out. Says FERC approval not required for contingency modeling enhancement. It just automates what is done manually now.

Jt. Parties: If I bid a resource on a sub-LAP basis, it follows instructions, if a contingency event occurs, why do you need a 20-minute dispatch to override cleared resources like mine?

ISO: contingency reserves are in the market; when a contingency occurs, put bids into the market

Jt. Parties: I submit a bid to participate at sub-LAP. The bid is accepted into the real-timer market. A contingency occurs. Does this override my schedule?

ISO: No. ISO market assumes you will meet the schedule.

Jt. Parties: Does the contingency allow local RA credit?

ISO: you are a planned resource. You do not qualify as local RA.

PG&E: You said you discovered due to SONGS that you had to review what was needed and what counted as local RA worked.

ISO: In the past, in other LCAs, had enough resources to meet need. Need to look at each area to see what is needed by sub-LAP. Until SONGS, had adequate resources due to those RA resources procured for system and local without DR. After SONGS retirement, it was borderline. Can we count on DR if short? Went through each program to see if met operational needs. In process, saw DR programs did not meet the current operational need. Loss of SONGS changed limiting contingency.