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Witness: Florio

PREPARED DIRECT TESTIMONY OF MICHEL PETER FLORIO

ADDRESSING SELECTED ISSUES REGARDING

ELECTRIC SYSTEM RELIABILITY FOR 2021

THE UTILITY REFORM NETWORK

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(15) Adopt an Emergency Load Reduction Program (ELRP) consistent with the discussion in Section IV.D.2 of this testimony.

(16) Order the changes to Investor-Owned Utility (IOU) demand response programs discussed in Section IV.D.3 of this testimony.

III. WHY ARE WE HERE? THE CONTEXT FOR THIS PROCEEDING.

On August 14, 2020, in the midst of an historic heat wave with temperatures 10-20 degrees above normal, the CAISO was faced with a shortage of supply to meet demand and was forced to declare a Stage 3 emergency for approximately one hour, resulting in rotating outages of firm load (rolling blackouts) of about 1000 Megawatts (MW). Almost one-half million customers experienced service outages lasting from 15 to 150 minutes. On August 15, similar conditions forced another Stage 3 emergency and the shedding of about 500 MW of firm load, which lasted only about 20 minutes, resulting in service outages for 321,000 customers over a period of 8 to 90 minutes.[1] These were the first rolling blackouts to impact the CAISO system since the Electricity Crisis of 2000-2001.

While these events were serious and produced a number of "lessons learned," particularly with regard to this Commission's Resource Adequacy (RA) program, it is important that they be viewed in context. Electrical systems, by virtue of the fact that electricity cannot yet be stored in large enough quantities to meet all instantaneous demands, are not designed to provide 100% reliable service under all conditions – to do so would be prohibitively expensive and ultimately unsuccessful. Rather, the system is, and has been for decades, planned to provide highly reliable but not perfect service at a reasonable cost. Planning standards throughout the industry are based on a Loss of Load Expectation (LOLE) of one day in ten years (in some places as stringent as one day in twenty years), with the understanding that some outages may still occur. To do

[1] *Preliminary Root Cause Analysis, Mid-August 202 Heat Storm*, October 6, 2020, prepared by the CAISO, the CPUC and the California Energy Commission (CEC), page 42, Tables 3.1 and 3.2.

otherwise would require the construction and funding of power plants that might sit idle for a decade or more without ever being needed to provide service—an obviously wasteful expenditure. Thus, the tradeoff between reliability and cost is inherent in the design of electrical systems, and plainly contemplates that some service interruptions will occur on rare occasions.

The heat storm that occurred in mid-August of 2020 was a 1-in-35-year event, with respect to the temperatures in California, the hottest August period since 1985.[2] The only other period on record with a similar heat wave occurred on July 21–25, 2006, and there were no rolling blackouts during that event, even though it set the still-existing peak demand record. The difference can probably be attributed to the fact that the August 2020 heat wave was West-wide, straining power systems through the Western Interconnection, while the July 2006 heat event was more focused on California. This meant that, in 2020, the other utilities in the West, which follow similar planning standards, did not have sufficient power to spare to export to California, as they had in 2006. The West-wide heat wave of August 2020 was therefore an even rarer event than July 2006 situation, although I am not aware of a specific quantification of its likelihood of recurrence.

The effects of climate change are likely to increase the frequency of such events, but in the near-term future are not likely to turn a 1-in-35-year heat wave into an every-year occurrence. This was a rare condition, and must be understood as such. Changing system planning standards to prevent the possibility of outages under such extreme conditions would be enormously costly and imprudent.

Even in the face of such extraordinary conditions, the CAISO system would likely have survived without service outages but for a software flaw that had yet to be discovered in the CAISO's Residual Unit Commitment (RUC) process. As explained in the CAISO Department

[2] *Id.* at 2.

of Market Monitoring's *Report on System and Market Conditions, Issues and Performance: August and September 2020*, dated November 24, 2020:

> Prior to September 5, any export that cleared the day-ahead market, such as the almost 3,000 MWs of exports that cleared during hour ending 19 on August 14 that were not wheels and not contracted to non-RA CAISO generation, was also given a higher scheduling priority than CAISO balancing area load by the real-time market. This could also have impacted reliability because cuts to export schedules in advisory runs of the real-time market could give CAISO operators advance warning to begin working with other balancing areas on whether or not CAISO native load or exports out of CAISO may need to be cut.
>
> On September 5, the ISO made important enhancements to RUC and the real-time scheduling priority of day-ahead energy market export schedules that do not receive RUC awards. RUC was adjusted to consistently reduce the RUC awards of exports not backed by contracts with specific generators when there was not enough physical supply to meet the CAISO load forecast. Export scheduling priorities were enhanced to only give exports that received RUC awards a higher scheduling priority than CAISO native load in the real-time markets. (Id. at 68-69

In short, the RUC process was intended to prevent the scheduling of power exports in the Day-Ahead (DA) market from RA capacity committed to California when the CAISO's own load forecast indicated that the power would be needed in Real-Time (RT) to meet internal CAISO load. Once accepted in the DA market, such scheduled exports are protected from curtailment for the purpose of serving internal CAISO load in the RT market. However, the software flaw prevented the RUC process from denying the scheduling of such power exports in the DA time frame. As noted by DMM, almost 3,000 MWs of such exports cleared the DA market for the hour ending 19 on August 14, the hour when the Stage 3 emergency occurred. Thus, if RUC had been functioning properly on August 14 and 15, it is quite likely that the shortages of 1000 MW on the 14th and 500 MW on the 15th would not have occurred.

Fortunately, the software flaw was found and corrected by September 5, 2020. As a result, the heat wave over Labor Day weekend, which was comparable to the events of mid-August, did not result in the need for any rolling blackouts (*Id.* at 9). The DMM Report states

that: "DMM supported these changes and believes that these changes played a key role in helping to improve real-time supply conditions on September 5 to 7 (*Id.* at 5).

Thus, in a very real sense, the problems that resulted in rolling blackouts on August 14 and 15 have already been fixed. That does not mean that there is not more to be done, however. California's reserve margin is still very tight, and additional procurement has already been ordered (and may be expanded in the near future) in the Integrated Resource Planning (IRP) proceeding. Similarly, problems with the RA program are currently undergoing intensive review in that docket. I am somewhat concerned that hurried activities in this docket may distract the parties' and the Commission's attention, and delay resolution of those critical proceedings unnecessarily. However, since this docket is already ongoing, there are some steps that this Commission can take to reduce the likelihood of firm load interruptions in the summer of 2021 *in the very unlikely event* that extreme temperatures similar to those experienced in 2020 were to be repeated again so soon after the last heat storm.

As another point of context, the rotating outages that took place on August 14 and 15, while of course undesirable, impacted far fewer customers and lasted for a much shorter time than some of the Public Safety Power Shutoff (PSPS) events that California has experienced in recent years. Similarly, various distribution-level outages impact multitudes of customers every year, sometimes for extended periods. From an end-user perspective, it does not matter if the cause of an outage is a PSPS event, a distribution system problem, or a shortage of generation – it is simply a power outage.

When considering what to do to minimize such outages, this Commission must consider how much more consumers (who are already burdened by the economic impacts of the Covid-19 pandemic) can afford to pay to improve service reliability. It is far from clear to me that those

expenditures are best directed toward obtaining a higher level of *generation* reliability, as opposed to reducing the impacts of PSPS events or more routine distribution outages. In terms of the consumers' ability to pay, there is an inherent tradeoff among these various objectives.

Unfortunately, the general public and elected officials tend to focus more attention on generation-induced outages, and assume that *someone* did something wrong if such interruptions occur. In reality, occasional – though rare -- generation shortages are the inevitable result of any reasonable planning regime that takes cost into account. The agencies that produced the *Preliminary Root Cause Analysis* might want to consider increasing their educational efforts on this point, so that the public and their elected leaders can better appreciate the tradeoffs involved.

IV. WHAT IS TO BE DONE? FOCUS ON THE DEMAND SIDE!

Given the political imperative to do *something* in response to the August 2020 outages, I recommend that this Commission focus its efforts on measures to reduce or moderate demand in preference to emergency measures to increase supply. Given that existing planning processes are already operating to procure sufficient generating capacity for all but the most extreme conditions, any effort to obtain greater reliability during such rare events should logically seek ways to moderate demand at those (hopefully rare) times when it is higher than reasonably anticipated. It makes little sense to incur the cost of building generation that will only be used once or twice a decade, when demand response is very well suited to meet such challenges.

The discussion from here on generally follows the outline of issues in the scoping memo.

A. Increase Supply During Peak and Net Peak Demand Hours?

I urge this Commission to act with extreme caution with respect to measures to increase supply for the summers of 2021 and 2022. The 3300 MW of procurement ordered in D.19-11-