Opinion on
Load Granularity Refinements

by

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I. Introduction

A lesson of the California crisis of 2000-2001—and of the history of power markets in general in the U.S.—is that in order to maximize the efficiency of market operations, avoid gaming, and provide incentives for appropriate resource siting, energy prices should reflect the cost of delivery, including the expense of location-specific congestion and losses. Transmission bottlenecks can significantly raise the marginal cost of delivery of wholesale power in load pockets compared to system-wide averages, while depressing prices in generation pockets. These cost differences vary greatly over time as system conditions change. Prices that reflect these costs provide needed incentives for resources to deliver supply or demand reductions where and when most needed. The CAISO's adoption of locational marginal pricing (LMP) under the 2009 Market Redesign and Technology Upgrade (MRTU) was a crucial step in providing these incentives in bulk power markets.

However, LMP is not applied to a large fraction of load in the CAISO markets, nor do most retail consumers in California face prices that reflect spatial variations in the marginal cost of service. Under the MRTU design, the bidding, scheduling and settlement of most of the ISO's internal load occurs at three large default load aggregation points (DLAPs). These DLAPs coincide with the service territories of the three California investor-owned utilities. The purpose of the DLAP design was to insulate wholesale load from locational cost impacts arising from the existing grid configuration. The justification for such insulation was that such load cannot respond to locational price signals because of the limited demand response products available when MRTU was implemented, and because CPUC retail rate-setting policies in California prevent CPUC jurisdiction retail customers from paying time-varying prices that reflect wholesale market conditions.[1]

The DLAP market design with three large DLAPs was part of the original MRTU proposal. This design feature was approved by FERC, but in their MRTU order they required the CAISO

[1] CAISO, *Load Granularity Refinements, Interim Proposal*, December 9, 2010, p. 2, www.caiso.com/Documents/LoadGranularityRefinementsInterimStrawProposal.pdf

to disaggregate the three DLAPs by Release 2 of MRTU, scheduled for three years after the implementation of MRTU.[2] Subsequently, based upon analyses by the ISO and MSC as well as stakeholder input, the CAISO requested a deferral of the implementation date for the disaggregation of the three default LAPs until 2014.[3] In response, FERC approved that request.[4] In 2014, the ISO then asked FERC for a permanent waiver from the ISO's obligation to further disaggregate DLAPs by MRTU Release 2.[5] FERC denied that request, granting the ISO a one-year extension to either comply with, or seek further relief from, the ISO's obligation to disaggregate the DLAPs and requesting additional study of the issue by the ISO.[6] Since then, the ISO has undertaken a stakeholder process and additional analyses, and proposes to petition FERC to be relieved of its obligation to further disaggregate its DLAPs.[7]

In the *long run*, we believe that efficient investment and operations of supply, transmission and distribution, and demand-side resources require that settlements be based on prices that are differentiated over space and time, reflecting actual system congestion and loss conditions. In designing the ideal market, the long-run benefits and costs of full implementation of LMP for all market participants should be evaluated. If full LMP is justified by benefits that clearly exceed costs, then the question of the best transition path to a full LMP market should also be addressed at that time. However, at the request of FERC, the issues addressed by the ISO's study are the immediate questions of whether the DLAP design should be retained, modified, or discarded in the short-run, and what the benefits would be of a move *now* to more disaggregated DLAPs or even full LMP for wholesale load.

The MSC has discussed and studied the issue of increasing the spatial granularity of load on several occasions. During a public meeting of the MSC on October 8, 2010, the ISO's 2010 granularity studies and stakeholder process were summarized by ISO staff. Dr. Frank Wolak, then Chair of the MSC, followed with a presentation of an empirical analysis of the dispersion of LMPs under MRTU within DLAPs.[8] He listed several categories of potential benefits and costs to consumers and the market of introducing greater spatial granularity in pricing to loads. Among the benefits he listed included incentives for consumers to favor transmission investments that increase market efficiency and lower the need for local market power mitigation, in-

[2] Paragraph 611 of FERC's September 21, 2006 *Order Conditionally Accepting the California Independent System Operator's Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade* (Docket No. ER06-615).

[3] CAISO, *Load Granularity Refinements, Interim Proposal*, op. cit.

[4] FERC, *Order Granting Extension of Time to Implement Default LAP Disaggregation* (Docket No. ER06-615), July 25, 2011.

[5] CAISO, *Motion of the CAISO for Waiver of Obligation to Disaggregate Default Load Aggregation Points*, Feb. 7, 2014.

[6] Order on Request for Waiver. Federal Energy Regulatory Commission. June 3, 2014. Docket Nos. ER06-615-000 ER02-1656-027 ER02-1656-029 ER02-1656-030 ER02-1656-031.

[7]CAISO, *Draft Final Proposal – Load Granularity Refinements*, www.caiso.com/Documents/DraftFinalProposal_LoadGranularityRefinements.pdf , March 24, 2015.

[8] F.A. Wolak, "Comments on Load Granularity," Oct. 8, 2010, www.caiso.com/Documents/ CommentsonLoadGranularity-MSCPresentation.pdf .

centives for efficient location of energy efficiency and demand response investments, and avoiding distortions arising from use of fixed load distribution factors. Among the cost categories identified by Dr. Wolak were changes in billing systems and the need to develop nodal-level load forecasting systems. He did not attempt to estimate the magnitudes of these benefits and costs, but he concluded that the costs would likely be small relative for all customers located in the State's population centers relative to the benefits to be derived from dynamic pricing and energy efficiency investments.[9] The MSC did not subsequently analyze the issue further, nor did it issue an opinion at that time on load granularity issues.

Since FERC's 2014 order requiring the ISO to address the issue with more analysis, the MSC has discussed the ISO's study at public meetings on Aug. 22 and Dec. 16, 2014, and Feb. 19, 2015. During the Dec. 16, 2014 meeting, MSC Member James Bushnell made a presentation on statistical approaches to analyzing price dispersion, and benefit-cost analysis approaches to quantifying the benefits of increased load granularity.[10] MSC members have also continued to provide informal advice to ISO staff on the design of LGR statistical and benefit studies.

In this opinion, we review the ISO's March 24, 2015 proposal,[11] including its study of price dispersion within DLAPs and the benefits analysis conducted to seek relief from FERC's requirement to disaggregate DLAPs. In the next section, we discuss the pricing study, as well as the ISO's estimation of costs of implementation. In Section III, we review the ISO's benefits study, and discuss the ISO's recommendation that DLAPs not be further disaggregated. Section IV summarizes our conclusions, which include the following. We find that the ISO's analysis supporting its recommendation for no further disaggregation is for the most part conservative, given its assumptions, in that it usually errs on the side of overestimation of the benefits of disaggregation of DLAPs. A very important assumption of the ISO's benefit assessment is that disaggregated prices would not be reflected in CPUC jurisdictional rates and that the lack of support for disaggregated prices from non-CPUC jurisdictional load serving entities would continue. Our major conclusion is that we support the ISO's recommendation against further disaggregation at this time because the likely benefits are small in the near future, and are likely to be well outweighed by the reported costs of implementation. This is because the CPUC has not made any efforts to date to modify retail rates based on locational wholesale prices, nor have they indicated that they will in the future. In addition, there is a lack of support for disaggregated prices from non-CPUC jurisdictional load serving entities. On the other hand, we do encourage reforms of retail ratemaking that would have those rates better reflect temporal and spatial variations in the cost of power to better enable price responsive consumers to adjust their consumption based on the cost of power.

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[9] As summarized in F.A. Wolak, "Memorandum to ISO Board of Governors, MSC Activities from August 23, 2010 to October 15, 2010," Oct. 26, 2010, www.caiso.com/Documents/101215MarketSurveillanceCommitteeUpdate.pdf .

[10] J. Bushnell, *Load Granularity Price Dispersion Study Discussion – Measuring the Implications of LAP Aggregation*, Presentation, Dec. 16, 2014, www.caiso.com/Documents/LoadGranularityPriceDispersionStudyDiscussion-MSC_Presentation-Dec2014.pdf

[11] CAISO, *Draft Final Proposal*, op. cit.

II. The CAISO pricing study

In its June 3, 2014 order,[12] the FERC expressed dissatisfaction with the previous pricing study and identified five specific areas for CAISO to address in its current study. These are:

1. Detailed description of the underlying data used.
2. An analysis of a reasonable range of different alternative levels of disaggregation.
3. Focused discussion of areas exhibiting the largest price differences.
4. Properly supported estimates of implementation costs for different levels of disaggregation.
5. An analysis of the entire CAISO footprint, including SDG&E.

The FERC order also raised issue with the use of annual average nodal price differences as the primary statistic for justifying its proposals and noted the absence of discussion of the effects of disaggregation on congestion revenue rights.

In its current study the CAISO has addressed each of these points.[13] While the analysis still includes an evaluation of annual average price differences in the day-ahead market, the CAISO also analyzes correlations of day-ahead market nodal prices with DLAP prices and the frequency of large differences between nodal and DLAP prices. The data sources are well documented and we believe that the motivation and description of the analysis is clearly explained.

1. Assessment of Annual Average Price Differences

We note that annual average price differences in the day-ahead market are the most relevant statistics for assessing the incentive that more disaggregated pricing would provide for long-run responses to differences in power prices. Examples of such responses include the locational decisions of large power consumers, investments to reduce power consumption, and installations of behind-the-meter generation. Furthermore, if retail prices are based upon averages of hourly energy costs, as they currently are for CAISO retail customers that are subject to CPUC jurisdiction, then annual averages are also the relevant time frame for short-run responses, even if the CPUC-jurisdictional suppliers bought and sold power at hourly nodal LMPs, as they do today. This is because retail prices will only reflect average differences over much longer time frames until such time that the CPUC choses to change the prevailing retail pricing design. Thus, the CAISO study's primary focus on annual average price differences in the day-ahead market is reasonable.

The CAISO's pricing study shows that, between 2011 and 2014, the vast majority of load was located at nodes with average LMPs in the day-ahead market that fell within $2/MWh of their DLAP price.[14] To put this finding into an economic context, we can compare this to the

[12] FERC, Order on Request for Waiver, op. cit..

[13] The most recent version of the pricing study is contained in the CAISO's *Draft Final Proposal*, op. cit..

[14] For the PG&E, SCE, and SDG&E DLAPs, 85%, 89%, and 90% of load was at nodes with LMPs that averaged with $2/MWh of their DLAP price, respectively (ibid., p. 14).

implied deadweight loss from such a price difference. Economists often utilize the concept of deadweight loss to quantify the inefficiency of market outcomes. The concept is illustrated in Figure 1, below.

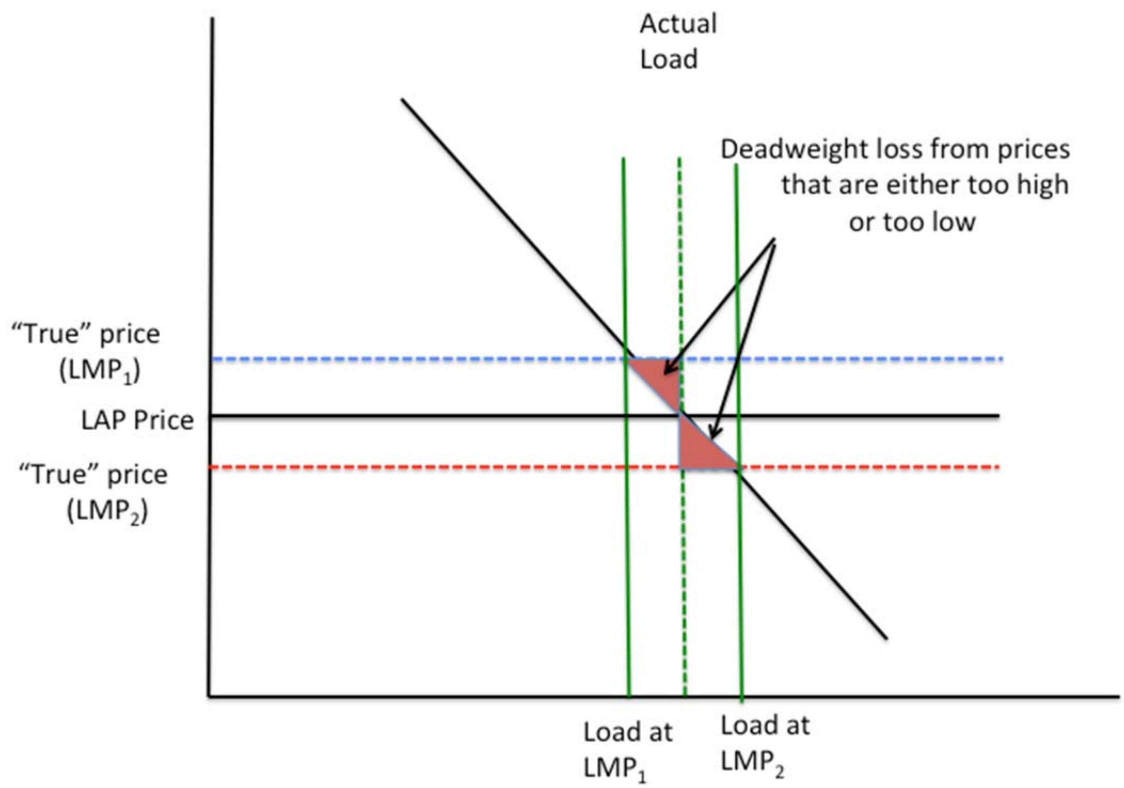

Figure 1. Deadweight loss from prices that are too high or low.

In the figure, the two triangles represent the deadweight loss. The upper triangle is the loss that occurs because the LAP price is too low relative to the local marginal cost of supply (LMP_1). As a result of too low a price, the actual load is higher than the efficient load (where the demand curve intersects LMP_1). The over-consumption results in a deadweight loss equal to the difference between the marginal cost of supplying power to that location and the marginal benefit of consumption (demand curve), which is the area of the upper triangle. In turn, the lower triangle is the social cost of under-consumption, where the ideal price is LMP_2, but local load pays the higher LAP price. The deadweight loss is the value of the consumption that should have taken place but didn't (the demand curve) minus the marginal cost of supply to that location (LMP_2).

As a very rough approximation to establish the relative magnitude of a deadweight loss from not reflecting such price differences in retail prices, we can apply the average 2013 CAISO day-ahead energy cost (excluding GMC) of $44.14/MWh and the average 2013 CAISO load of 26,460 MW.[15] If we further assume a demand elasticity of -0.275 and assume a linear demand

[15] *Annual Report on Market Issues and Performance*. Department of Market Monitoring. California ISO. April 2014.

function, the implied slope of the average demand function would be about -0.00607 (\$/MWh)/MW, or -165 MW/(\$/MWh).[16]

We can now obtain an estimate of the deadweight loss based on the elasticity, if we make the very conservative assumptions that 1) the average price difference is \$2, and 2) that charging LMPs at the wholesale level would result in moving all retail load \$2 closer to a price equal to marginal cost. Then the benefits in terms of reduced deadweight loss due to long-run changes in power demand in response to long-run differences in the cost of meeting load at locations within a common DLAP would be about \$2.9 million/year.[17] This benefit estimate depends only on the elasticity, quantity of demand, prices, and dispersion of LMPs, and not on the whether the average retail prices are close to the LAP price or not.[18]

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[16] Ito estimates a residential medium-run elasticity of -0.2 (K. Ito, "Do consumers respond to marginal or average price? Evidence from nonlinear electricity pricing," *American Economic Review*, forthcoming). As discussed in Borenstein et al. (S. Borenstein, J. Bushnell, F. Wolak, and M. Zaragoza-Watkins, "Report of the Market Simulation Group on Competitive Supply/Demand Balance in the California Allowance Market and the Potential for Market Manipulation," Report to the California Air Resources Board, June 2014), there are few estimates for commercial and industrial elasticities. The only published study from the last 20 years they find is D.R. Kamerschen and D.V. Porter's analysis ("The demand for residential, industrial and total electricity, 1973-1998," *Energy Economics*, 26(1), (2004): 87-100), which estimates a long-run industrial price elasticity of demand of -0.35 when controlling for heating and cooling degree-days. We arrive at -0.275 by assuming half of load is at the higher elasticity and half at the lower residential value. Under an assumption of linear demand, the deadweight loss estimate is scalable so that, for example, doubling the elasticity would double the DWL to roughly \$6 million.

[17] Assuming a slope of 165 MW/\$, the area of the deadweight loss triangle would be 2x2x165x1/2 per hour. Over the 8760 hours in the year, this implies \$330 hour x 8760 hours = \$2,891,000 in reduced deadweight loss per year from implementing more disaggregated pricing in the day-ahead market.

As implied by the previous footnote, this efficiency gain (reduction in loss) is proportional to the price elasticity. However, under the same linear assumption, the relationship of efficiency gain to the price changes themselves is nonlinear (more precisely, quadratic), so that, for example, if the range of prices doubles, then the deadweight loss quadruples. As a consequence, if LMPs vary only by a small amount (say a dollar or two) around the PLAP, then there is relatively little to be gained by increasing load granularity, but the benefits increase rapidly if the prices vary by much more (say by 5-10 \$/MWh around the PLAP).

[18] For instance, assume that the LAP price is instead \$30/MWh rather than \$44.14, as assumed above, while the retail price is still \$44.14. Assume further than LMP_1 = \$32/MWh for one-half of the load, while for the other half LMP_2 = \$28/MWh. If the retail prices for those respective groups of customers were changed to reflect the LMP differences (\$46.14 and \$42.14 per MWh, respectively), then the reduction in dead-weight loss would again be very roughly \$2.9 million per year.

The calculation proceeds as follows. The change in consumption for customer group 1 would be -165 MW (which results from a -0.275 elasticity applied to a price change of +\$2/\$44.14 = +4.5% and a load of 13,23 = 26,460/2 MW), while group 2 would have a change of +165 MW. The change in the value of the two group's consumption (integral of the demand curves) would be -165 MW *(\$46.14+\$44.14/MWh)/2 = -\$7441/hr and +165 MW*(\$42.14+\$44.14/MWh)/2 = + \$7111/hr, respectively. The total change in cost would be -165 MW*32 \$/MWh + 165 MW*28 \$/MWh = -\$659/hr. Subtracting the change in cost from the sum of the value of consumption for the two groups results in a welfare gain (deadweight loss reduction) of \$329/hr, or \$2.9 million/year, as before. In sum, aligning retail price differences over space (or time, for that matter) with marginal cost differences is beneficial, even if prices differ systematically from marginal costs.

As we discuss below, there are several reasons why it is uncertain whether more disaggregated wholesale pricing by the CAISO would be reflected in retail prices to the extent required to realize these benefits. Even so, the benefits from these long-term changes in consumption would be relatively small in terms of traditional economic loss, as they are just a fraction of the estimated implementation costs that were reported by load-serving entities in California in response to the CAISO's request for estimates of such costs. In their responses, stakeholders estimated their upfront investment costs to be on the order of $100 million, while on-going annual costs would be over $10 million/year. Even if those implementation costs were overestimated by, say, a factor of three, they were still well in excess of our estimate of the reduction of deadweight losses.

2. *Focused Discussion on Locations and Sources of Price Differences*

The CAISO pricing study concluded that it is difficult to identify obvious new pricing zones from the pattern of differences between LMP and DLAP prices that did arise during 2011-2014. In some cases, the CAISO found it difficult to group price differences into geographically contiguous areas, particularly when those differences were driven by losses.[19] In other cases, diverging LMPs were clustered but the CAISO concluded that the price differences are transient, being unlikely to persist because of transmission reinforcements or other reasons.

The one possible zone identified by CAISO's study is in the greater Fresno area. LMPs in the Fresno area were, on average, over $3 per megawatt hour higher than the PG&E DLAP price over the four year study period.[20] The CAISO analysis traces a primary cause of this divergence to peak hours during July and August of 2014, when drought conditions apparently created unusual congestion patterns for this area.

Furthermore, the CAISO proposal also states that transmission projects likely to reduce or eliminate this congestion have already been identified and approved. The CAISO argues that once these transmission projects are completed and normal hydrological conditions return, Fresno area LMPs will likely return to levels closer to other PG&E nodal LMPs. The CAISO pricing study concludes that there is no logical level of spatial disaggregation to analyze short of nodal.[21]

III. The CAISO Proposal and Analysis

The CAISO study cites four areas of potential benefits from further spatial disaggregation, discussed below, and finds that these benefits would be less than $3 million annually.[22] By contrast, the implementation costs identified by participants for a fully nodal implementation would include $14.6 million in implementation costs, $132.6 million in capital costs and $12.6 million in ongoing annual costs. Since the identified estimated benefits fall far short of the estimates of

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[19] See *Draft Final Proposal*, p. 19.

[20] Ibid., p. 26.

[21] Ibid., p. 14.

[22] Ibid., p. 41.

the costs of implementation, the CAISO concludes that the current level of price aggregation for load is just and reasonable and that no further disaggregation should be implemented at this time.[23]

In this section, we will comment briefly on the CAISO's analysis of the benefits of disaggregation and discuss the more difficult question of the proper context in which such an analysis should be performed. In short, we agree with the CAISO that given the apparent unwillingness of the CPUC to reflect locational price differences in the retail rates subject to its jurisdiction, [24] and the lack of interest in further price disaggregation by retail access load-serving entities,[25] by municipal utilities purchasing power at DLAP prices, [26] or by large power consumers, the benefits of further LAP disaggregation appear to be relatively small and would be outweighed by the apparent cost of implementation.

We also note that "just and reasonable" is not the same standard as "most long-run efficient." We support the view that fully nodal pricing or less aggregated zonal pricing would better support economic efficiency in the long-run, and would better enable price responsive load to reduce the need for incremental investment in generation and transmission, at least in the short-run. From a long-run economic efficiency perspective, the most attractive eventual paradigm for any electricity market would be one in which customers are exposed to -- and given the opportunity to adjust their power consumption in response to -- both the spatial and temporal variation in locational marginal prices, without the implementation costs and inflexibilities of "negawatt"-based demand response programs.

It is clear that those ideal conditions do not today exist in California today. A more difficult question is the degree to which ISOs, by adopting fully nodal pricing for loads, provide leadership that can influence state policies concerning retail pricing in one way or another. This is both a controversial and difficult to quantify concept.

A. Benefits Assessment

The CAISO study identifies and considers the quantification of three potential categories of benefits, including

1) Investment Incentives,
2) Hedging of Congestion Costs,
3) Efficiency of day-ahead market pricing.

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[23] Ibid., p. 3.

[24] Comments of CPUC Staff, March 17, 2015

[25] See Comments of Alliance for Retail Energy markets, March 13, 2015, Comments of CLECA, April 3, 2015, Comments of Energy Users Forum and California Manufacturers and Technology Association, March 17, 2015, and Marin Clean Energy, March 3, 2015.

[26] See Comments of Northern California Power Agency, April 10, 2015; Comments on Behalf of the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside California, March 13, 2015.Comments on Behalf of California Municipal Utilities Association, April 13, 2015

The ISO's conclusions about each of those are reviewed in the subsections below.

In addition to those benefits, there are several other categories of potential benefits that might, in theory, be relevant, and we discuss several of those in Section III.B, below. We have already discussed one major category: the effect of local prices on the efficiency of electricity consumption, which would be the reductions in dead-weight loss we quantified in Section II. During the stakeholder process for this initiative, there was extensive discussion of both the qualitative and quantitative nature of any potential benefits with respect to end-use consumption. At issue was the extent to which any such benefits could be considered a result of CAISO wholesale pricing policies. For example the CPUC has concluded that "virtually all the benefits purportedly achievable from price disaggregation can be and/or are realized by existing market products, process and information."[27]

As a result of this stakeholder process, the CAISO proposal concluded that any benefits with respect to end-use consumer behavior fall under the rubric of retail pricing policies rather than wholesale market design. Thus they concluded that it would not be relevant to consider these types of benefits, such as the deadweight loss calculation we described in section II, as part of this process.

While we do not disagree with this conclusion, we note in addition that the magnitude of the deadweight loss appears to be relatively small compared to estimates of implementation costs. As noted above, assuming that all customers at all nodes had their rates adjusted according to their *annual average* nodal energy prices, rather than dynamically reflecting hourly DLAP prices, would imply a reduction in deadweight loss on the order of $3 million per year.

There are a few reasons why our very rough estimate of consumption-based inefficiency due to DLAP pricing could be understated. First, if a significant number of customers faced *hourly* nodal prices this number would most certainly increase. Second, if some customers had access to real-time nodal prices, then the larger price variations in real-time nodal prices imply more potential efficiency gains. Some large customers in California who can take advantage of retail access may presently face real-time prices on the margin from their providers. To the extent that this is the case, then the deadweight loss reductions may be somewhat higher than we have calculated.

1. *Investment Incentives*

The CAISO proposal identifies a few areas where locational pricing signals provide value to the decision on whether to invest capital or make other long-run commitments with regards to energy production, consumption, or transmission. The CAISO concludes there are no material benefits to further disaggregation because spatial granularity is already provided for almost any relevant investment decision. [28] First, generation is already exposed to fully granular nodal pricing. Second, transmission investment is initiated through a planning process that already takes

[27] California Public Utilities Commission, March 17, 2015 p. 3

[28] *Draft Final Proposal,* op. cit., pp. 32-33.

into account the underlying nodal energy prices for load, even though load is not paying those exact prices. Third, major end-use consumers that are able to respond to dispatch instructions have the option of becoming a participating load thus making them eligible for paying the nodal, rather than DLAP price. Similarly, end use customers able to provide demand response, can enroll as proxy demand resources and buy power at the nodal price. However, either option for consumers has high participation costs compared to the costs that would be faced if a power consumer instead had the option of being able to respond to real-time locational prices. Neither the participating load or proxy demand resource option would be available to power consumers who simply wish to be able to respond to nodal prices, but do not want to be dispatchable or provide demand response.[29]

The only remaining source of improved investment incentives relating to long-run locational price differences would therefore reside with durable goods purchases by end-use consumers who are not realistically able to become either participating loads or proxy demand resources. If retail pricing policies were to be changed so that all consumers faced retail prices whose differences over space reflected annual average differences in LMPs, then as we speculated in Section II, there might be an additional $2.9 million or so per year of benefits. However, there is no prospect at this time of such a policy change, so it is not reasonable to add this figure to the benefits calculated in the ISO's study.

2. Congestion Revenue Rights

The FERC order also identified congestion revenue rights as an area of potential benefits from increased granularity in wholesale pricing. The CAISO analysis also discusses this category of potential benefits in detail. The CAISO suggests that these benefits can arise because the simultaneous feasibility test used to allocate CRRs is artificially constrained by the DLAP paradigm. This is because all CRRs in the Tier 1 annual allocation process are treated in the CRR model as sinking at demand nodes within a LAP according to a fixed load distribution factor (LDF). In order to maintain feasibility when allocating CRRs, the process is forced to curtail these sinks proportionally to the LDFs. The CAISO identifies a concern that if desired distribution of CRRs was not proportional to these LDFs, this limitation to the feasibility test can restrict the amount of CRRs that are allocated, even though the desired group of CRRs may in fact be feasible for the actual network.

The CAISO analysis estimates an upper bound on the benefits that could be created by awarding additional CRRs by nominating them as sinking at nodes rather than DLAPs. The resulting bound upon possible benefits ranges between $1.08 to $2.75 million per year based on CRRs nominated in Tier 1 but not awarded because of infeasibility. These values are derived

[29] See for example, California ISO, *Load Granularity Refinements, Draft Final Proposal*, September 18, 2013, www.caiso.com/Documents/DraftFinalProposal-LoadGranularityRefinementSep18_2013.pdf, p. 11. We have been informed by ISO staff that participating demand response loads have to have a minimum curtailable load of 100 kW, unless the load also wants to provide ancillary services, in which case the minimum load is 500 kW. Proxy demand response is only available to a load-serving entity that is both procuring the wholesale energy and, at the same time, is acting as the demand response provider and selling that energy back to the ISO.

from the monthly auction price.[30] The proposal characterizes this estimate as an upper bound for several reasons, including the fact that some of the CRRs unallocated in the annual process can be freed up in a subsequent distribution that allows for nominations at the sub-LAP level. Moreover, CRRs sinking at individual nodes can be obtained in the CRR auctions, so the DLAP aggregation does not prevent feasible individual CRRs from being acquired by load serving entities and used to hedge congestion costs in the day-ahead market.

Another reason that the CAISO estimate is an upper bound is that the hedging value of a CRR is at most a fraction of its auction value. The only efficiency loss from a potential shortfall of available CRRs would be related to any inefficient level of risk that potential CRR purchasers are required to take on when they are not able to acquire CRRs that would hedge congestion costs to the actual location of their load. This is the concept of *certainty equivalent*, where risk-averse firms are willing to pay a premium above the expected value of a revenue or cost stream in order to lock in that value with certainty. A rough estimate of this certainty equivalent could be gleaned from their willingness to pay for CRRs relative to the expected value of the congestion revenue stream. The hedging value would be measured by the risk premium in the CRR auction price relative to the expected payout. The expected payout is not observed, however, and the variability of actual payouts makes it difficult to infer the risk premium component of particular CRRs from the limited data on actual outcomes that is available.[31]

The CAISO's upper bound estimates do not measure the hedging value of the incremental CRRs, but instead use the *full* auction price (a close proxy for willingness to pay) applied to the CRRs requested in Tier 1 that were infeasible. This is in effect assuming that the associated revenues with the CRRs are worth nothing to their purchasers and that the entire bid price reflects the risk premium component. This is almost certainly a very conservative assumption in favor of finding large benefits.

There is, however, a slightly different hedging issue which is intrinsic to DLAPs. This arises for consumers whose load is not located at the DLAP. In that case, requiring them to hedge their load as if it is located at the DLAP, when it is in fact not, can cause CRR feasibility problems. In particular, CRRs that would hedge these loads by sinking at the DLAP at the margin could be infeasible by the CAISO simultaneous feasibility test, even though CRRs sinking at the location of their actual load would be feasible. This would be a potential concern for municipal utilities and retail access customers.

[30] CAISO Draft Proposal, March 24, 2015, op. cit., p. 35.

[31] We understand that the prices for financial transmission rights in PJM and MISO often show significant risk premia. One analysis of data on prices and payoffs for congestion revenue rights in the NYISO (which are called TCCs in that market) claims to have found insignificant risk premia in the portion of the state outside NY City and Long Island, and large profits (excess of expected payoffs over CRR prices) in the latter region (S. Adamson, T. Noeb, and G. Parker, "Efficiency of financial transmission rights markets in centrally coordinated periodic auctions," *Energy Economics*, 32(4), 2010, 771–778). However, the prices and payoffs for TCCs sinking in the major congested load centers show a substantial long run average premium of the TCC price over the average payout.

One could place an upper bound on the benefits from greater DLAP disaggregation in terms of CRR hedging using the value of the CRRs nominated in any tier that were infeasible. But this would overstate the actual benefits because, first, not all of those CRRs might be feasible if they sank at the location of the actual load and, second, as noted above, the hedging value of a CRR is at most a fraction of its auction value. In any case, none of the municipal utilities or retail access customers or suppliers that might be impacted by this outcome expressed a desire for further disaggregation in DLAPs, so they do not appear to expect material benefits in terms of lower hedging costs or better hedging ability from locational price disaggregation.[32]

3. Day-ahead market pricing efficiency

Another potential benefit to increased granularity in the pricing of load that evaluated by the CAISO would be the ability to perform the day-ahead market optimization with more flexibility in adjusting load at different locations. The CAISO's day-ahead optimization, like the annual CRR allocation process, must clear load at all nodes in proportion to the load distribution factors used to define the DLAP in the day-ahead market and therefore can reduce transmission overloads through load adjustments only by reducing *all* nodal loads within a LAP in proportion to the load distribution factors. For example in order to use load to reduce overloads on paths into the San Francisco Bay Area, the optimization must reduce the amount of load that clears in the PG&E service territory , rather than hypothetically reducing the amount of load the clears only in Bay Area. The CAISO's analysis then observes that the extent to which DLAP load bids do not clear because of congestion within the DLAPs reduces the ability of LSEs to hedge in the day-ahead market. The analysis seeks to assess the magnitude of the inefficiency by reviewing the frequency with which DLAP bids are on the margin in the day-ahead market.[33]

In evaluating this issue one needs to keep in mind that we are not assessing a situation in which load cannot be met within part of the DLAP because of congestion, but simply the need to dispatch generation out of merit within part of the DLAP to manage congestion. Hence, when a DLAP load bid does not clear, it is because it is bid at a price level that is too low to allow some higher cost generation in the constrained region to clear, because that would boost the overall DLAP price above the price of the demand bid. The underlying problem is that submitting demand price bids for regions as large as some of the California DLAPs requires that load serving entities assess two quantities: first, at what price level to submit demand bids to avoid paying unduly high prices for power over the LAPs, while accounting for the level of variability and unpredictability in the general price level, and second at what price level to submit demand bids to avoid buying power at unduly high prices due to factors inflating the price of power within a part of the DLAP. Large DLAPs with price differences within them require load serving entities to trade off the two objectives, choosing between paying too much in subregions when something distorts the price of power in the day-ahead market and selecting bid levels for the LAP

[32] See Comments of Northern California Power Agency, April 10, 2015; Comments on Behalf of the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside California, March 13, 2015; Comments on Behalf of California Municipal Utilities Association, April 13, 2015. This lack of benefits may reflect the use of the MSS load following option by municipal utilities that would have been most adversely impacted by settling their load at the DLAP.

[33] See *Draft Final Proposal*, March 24, 2015, op. cit., p. 39.

that do not clear because of normal variability in market conditions, leaving the load serving entity exposed to real-time price volatility. It is undoubtedly hard for load serving entities to accurately project the competitive level of day-ahead market prices in any case and this difficulty is exacerbated by having to make this assessment over such a broad region. If there were transmission constraints within the DLAPs that frequently bind with high shadow prices, the use of these DLAPs would make it very difficult for load serving entities to submit rational downward sloping load bids.

Load serving entities do not necessarily need to submit price capped load bids, and the issues identified by the CAISO do not arise if load serving entities instead submit price taking bids. However, submitting price taking load bids can make a load serving entity more vulnerable to high prices that can arise for several reasons. These include: the exercise of market power in the day-ahead market; distortions in day-ahead market prices due to virtual bids motivated by other financial positions that cause day-ahead market prices to exceed expected real-time prices; mistaken load weights used by the CAISO in its day-ahead market model; and physical or virtual bids by other market participants that are driven by mistaken expectations. These considerations may not be particularly large in the CAISO because of the presence of extensive market power mitigation rules and rules preventing the use of virtual bids to benefit CRR positions. Nonetheless, the use of DLAPs increases the exposure of load serving entities to such distortions in day-ahead market prices to an extent that would not exist with more disaggregated pricing. Perhaps for this reason, it appears from the CAISO comments that load serving entities in California find it prudent to submit price capped load bids to limit their exposure to day-ahead market prices that are inconsistent with the real-time prices the entities expect.

As the California ISO notes, load serving entities can achieve essentially the same protection against clearing load bids at anomalously high day-ahead market prices by submitting virtual supply bids. [34] We do not have a sufficiently precise understanding of the constraints the CPUC has placed on virtual bidding by jurisdictional load serving entities but it could allow them to submit virtual supply bids in this manner, and other load serving entities certainly could do so. Indeed, load serving entities are submitting virtual supply bids today and some might be motivated by these considerations.[35] However, the ability to achieve the same outcome with nodal virtual supply bids as with price capped load bids does not mean that the benefits from more disaggregated bidding would be zero as asserted by the California ISO. Rather, it means that the benefits would be capped by the cost of using virtual supply bids for this purpose.[36]

[34] Ibid., p. 40.

[35] California ISO, Department of Market Monitoring, *2013 Annual Report on Market Issues & Performance*, p. 118, Table 4.1 It is possible and perhaps likely that these virtual supply bids are in fact motivated by other considerations, such as supply resources under contract to the utility that do not bid into the day-ahead market. However, we do not have access to the data needed to assess the motivation for these bids.

[36] The CAISO figures regarding the frequency with which DLAP bids are marginal are not informative as to the magnitude of the benefits. This is because there can be losses from the inability to submit downward sloping load bids at a more disaggregate level not only when the bids do not clear at the DLAP level but also when the DLAP bids *do* clear only because they were required to be submitted as aggregated across nodes, and more disaggregate bids would *not* have cleared.

Hence the benefits for the large investor owned utilities that serve load throughout the DLAPs would be capped by the costs they would incur if they submitted virtual supply bids to compensate for the inability to submit more disaggregated load bids. This would include the fee on virtual bids plus the uplift costs allocated to virtual supply bids, which was around 46 cents per megawatt hour in 2013.[37] The costs of using such a bidding strategy based on virtual bids would be much higher for non-jurisdictional load serving entities, such as municipal utilities and retail access suppliers. This is because they would also need to evaluate the expected real-time price at all the locations where they have no load but the investor owned utilities do serve load, instead of just needing to evaluate the expected real-time price at the location where they serve physical load,

However, as noted above, none of the municipal utilities nor retail access suppliers support more disaggregation of load pricing, so they must not believe these costs from being unable to submit more effective price capped bids to be material.[38] Similarly, none of the CPUC jurisdictional investor owned utilities supports more disaggregation of load pricing so they also presumably do not believe these costs are material.[39] This lack of interest in disaggregation may reflect their perception of a relative lack of congestion in the day-ahead market that would cause material dispersion in day-ahead market prices within the DLAPs.

It is difficult to quantify this effect, in part because of the difficulty in imagining what the counter-factual bidding of demand at individual nodes would be under a fully nodal regime. The amount of data available for such an analysis was also severely constrained by changes to the CAISO software that coincided with the implementation of its fifteen minute market.

B. Other Possible Sources of Benefits

In addition, there were other benefits that were not considered by the CAISO. These include the benefits of power consumers being able to respond to locational differences in real-time prices, reductions in CRR congestion rent shortfalls due to differences in within-DLAP load weights between the CRR allocation process and the day-ahead market, and consistent pricing for behind-the-meter generation. We define each of the categories below, and although in theory they could be important, we conclude that none is likely to be significant in the near term.

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[37] California ISO, Department of Market Monitoring, *2013 Annual Report on Market Issues & Performance*, pp. 118 and 120.

[38] See Comments of Northern California Power Agency, April 10, 2015; Comments on Behalf of the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside California, March 13, 2015; Comments on Behalf of California Municipal Utilities Association, April 13, 2015; Comments of Alliance for Retail Energy Markets, March 13, 2015, Comments of CLECA, April 3, 2015, Comments of Energy Users Forum and California Manufacturers and Technology Association, March 17, 2015, and Marin Clean Energy, March 3, 2015.

[39] See Comments of Pacific Gas & Electric, March 13, 2015, and Southern California Edison Stakeholder Comments April 20, 2015.

1. *Response to real-time prices*

The CAISO's analysis of price differences within the DLAPS was limited to day-ahead market prices. There is considerable volatility in real-time prices and there could be value in retail power consumers being able to adjust their consumption in response to large differences in real-time power prices within the LAP. In addition to reducing the cost of meeting load in real-time, such a real-time locational price signal for price responsive load might reduce the need for transmission and generation in the long run by enabling the CAISO to reliably meet load with fewer resources. Although we are unaware of whether there are presently significant numbers of direct access customers in the CAISO footprint who face real-time prices on the margin, this can and, we hope, will change in the future.

This functionality could also be provided by proxy demand resources, CPUC jurisdictional demand response and participating loads. But these are relatively high cost mechanisms as illustrated by the lack of any proxy demand resources, the very small number of participating loads resources, and the lack of real-time price response from CPUC jurisdictional demand response programs.

However, given the reluctance to date of the CPUC to embrace price responsive load among its jurisdictional customers and the lack of support from municipal utilities, retail access suppliers or large power consumers for greater locational price disaggregation, there is no evidence that there could be significant benefits of this type in the near term.

2. *Day-ahead market congestion rent shortfalls*

The CAISO analysis also considers the effect that more granular pricing could have on CRR revenue adequacy presently caused by the use of large DLAPs. At present the CAISO uses a single set of load weights to evaluate the feasibility of CRRs in the allocation and auction process and then different sets of load weights in the day-ahead market for each day. The large DLAPs inevitably lead to some infeasibility when awarded CRRs are subsequently infeasible when day-ahead market load weights are used. There would also be some offsetting surpluses when additional CRRs would be feasible with day-ahead market load weights.[40] The CAISO discussion argues that revenue inadequacy is primarily driven by differences between the day-ahead model and CRR model that are unrelated to LAP aggregation, and therefore sees no quantifiable benefit from disaggregation with regards to revenue adequacy.

However, there is a potential for CRR auction participants to magnify the shortfalls and create cost shifts by buying portfolios of nodal CRRs and LAP CRRs that have low constraint impacts at auction weights but potentially larger constraint impacts at day-ahead market weights. Shifting to less aggregated DLAPs would reduce the potential for these shortfalls and strategies.

These wealth transfers could also be avoided while continuing to settle load at the DLAPs by using the auction load weights to settle CRRs in the day-ahead market. Hence, the magnitude of the benefits from reducing these wealth transfers by implementing smaller DLAPs would be

[40] *Draft Final Proposal*, March 24, 2015, op. cit., p. 37.

capped by the cost of shifting to using auction load weights to settle CRRs in the day-ahead market.

The CAISO analysis also discusses additional ways in which granular pricing might negatively impact CRR revenue adequacy. For instance, as noted in Section III.A.2 of the draft final proposal,[41] further disaggregation could result in an increase of allocated CRRs in the Tier 1 annual allocation process, which have the potential to displace feasible CRRs that are currently awarded through the auction process. Therefore, there could be a decrease in CRR auction revenues, which are included in the CRR balancing account, thus decreasing revenue adequacy.

3. *Behind-the-meter generation*

The current proposed design for accommodating behind-the-meter generation in the CAISO market provides for such generation that participates in the CPUC resource adequacy design to settle at nodal prices.[42] Retention of the DLAPs will create an incentive for behind-the-meter generation at locations with high prices to participate in the resource adequacy process and sell their power at the nodal price, and for resources at low priced locations to remain behind the meter and in effect sell their output at the DLAP price. This incentive will be small as long as price differences within the DLAP are small but it will be large at any locations with large price differences.

IV. Conclusion

While there are a number of potential benefits from increased disaggregation in load pricing, neither market participants nor the CPUC expect these benefits to be sufficient to make such a change cost-effective. The CAISO has compiled data showing that differences between nodal and DLAP prices in the day-ahead market have generally been small, particularly in the earlier years. These historical congestion patterns may of course not persist in coming years and congestion may increase. Alternatively, changes in the resource mix may cause day-ahead market congestion to become even smaller.

Thus, we support the ISO's proposal to maintain the status quo and not pursue further disaggregation of the existing DLAPs at this time. We support the long term vision of retail prices that reflect system conditions that vary over space and time so as to promote efficient coordination of resources in both wholesale and retail markets. However, in the absence of retail rate reform that would allow most customers to face such prices on the margin, there is little benefit to providing more spatial price granularity for load at this time, which would be greatly outweighed by the reported cost of implementation. On the other hand, we do encourage reforms of retail ratemaking that would have those rates better reflect temporal and spatial variations in the cost of power to better enable price responsive consumers to adjust their consumption based on the cost of power.

[41] Ibid., p. 38.

[42] California ISO, *Reliability Services, Addendum to the Draft Final Proposal*, February 27, 2015, Section 4.3.1 describes requirements to be a participating generator or system resource.