BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)	
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005
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INFORMAL COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON THE ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING THE DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK FILING AND PROCESS REQUIREMENTS

Alex J. Morris
Executive Director

Jin Noh
Senior Policy Manager

CALIFORNIA ENERGY STORAGE ALLIANCE
2150 Allston Way, Suite 400
Berkeley, California 94704
Telephone: (510) 665-7811
Email: cesa_regulatory@storagealliance.org

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Pursuant to the California Public Utilities Commission ("Commission") Energy Division and their instructions and request for informal comments on the *Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Filing and Process Requirements* ("Ruling"), issued by Administrative Law Judge ("ALJ") Robert M. Mason III on November 8, 2019, the California Energy Storage Alliance ("CESA") hereby submits these informal comments and serves them to the service lists of R.14-08-013 and R.14-10-003.

I. INTRODUCTION & SUMMARY.

CESA commends the Commission for adopting a number of critical reforms that will enhance the Distribution Investment Deferral Framework ("DIDF"), improve the Grid Needs Assessment ("GNA") and Distribution Deferral Opportunity Report ("DDOR"), and ultimately increase the viability of distributed energy resources ("DERs") being able to cost-effectively defer distribution capital investments. CESA is largely supportive of many of the reforms included in the Ruling but also understands how time and resource constraints make it challenging to implement all of these reforms in the upcoming 2020-2021 DIDF cycle. In reviewing the long list of 56 reforms, there are some reforms that likely require further refinement to ensure effective implementation and fair and reasonable outcomes before full-blown implementation. Thus, in response to the Energy Division's call for informal comments on each of the reforms, CESA offers our recommendations on how to prioritize the multitude of reforms and focuses our general comments on a few specific reforms in order to inform Energy Division's implementation of the reforms:

- Unless alternative models are developed, a narrower set of deferral opportunities with greater certainty will likely lead to greater success of deferral under the current DIDF process.
- The evaluation of option value should be incorporated into contracts and solicitation documents.
- Standardization of screening criteria and prioritization metrics would support stakeholder review but certain reform items can be deferred to next year's cycle.
- Implementation of the fire-threat and Public Safety Power Shut-off ("PSPS") outage data should be prioritized among the data availability reforms.
- The consistent incrementality evaluation methodology across utility solicitations is laudable and the Commission should explore a broader incrementality policy across all planning processes.

- Value stacking and coordination of multiple procurement objectives should be encouraged and continue to be explored but the short solicitation windows suggest that distribution-only solicitation may be feasible.

- Refinements to contracting and performance requirements for reliability projects should be pursued.

- Utility-owned deferral projects should be eligibility in future solicitations but additional development of guardrails and frameworks is needed.

- Tariff-based sourcing mechanisms should be revived for further discussion and consideration.

II. UNLESS ALTERNATIVE MODELS ARE DEVELOPED, A NARROWER SET OF DEFERRAL OPPORTUNITIES WITHER GREATER WILL LIKELY LEAD TO GREATER SUCCESS OF DEFERRAL UNDER THE CURRENT DIDF PROCESS.

In principle, CESA agrees with the Ruling's general direction that the DIDF process should continue to advance as many deferral opportunities as possible through adjustments to the screening criteria and prioritization metrics, including for the distribution components of pre-application projects.[1] However, CESA is reassessing whether such an all-inclusive approach would lead to or increase the likelihood of successful deferrals based on recent experience with the DIDF Request for Offers ("RFO"). Specifically, there is a "moving target" concern with forecast and cost adjustments that lead to the significant scope change for some projects, a changing "bogey" to beat, or a cancellation of the deferral solicitation altogether. Without much certainty about service requirements or the deferral value of a project/bid, developers face significant risk that their development efforts (*e.g.*, site and/or customer acquisition, interconnection study costs) could be wasted through an update process that overlaps with the solicitation launch, evaluation, and contracting period. For example, the utilities' annual distribution planning processes currently extend and overlap with the Integrated Energy Policy

[1] Ruling at 31, 58, 60, and 64.

Report ("IEPR") finalization in Q1 of every year, where forecasts may change year to year. Though the three-year timing screen is intended to minimize such uncertainty, these macro-level forecast adjustments can have material impacts on the viability of deferral projects.

A slightly different issue is around known load growth projects, which often represent "lumpy" load additions with seemingly unclear expectations and/or short timelines. This can significantly impact how the utilities disaggregate the system-level IEPR forecasts and substantially change the service requirements from a high-potential project with achievable service requirements (*e.g.*, manageable duration needs) to one that is nearly impossible for many DERs (*e.g.*, 24x7 baseload needs). For example, stakeholders experienced this in the recent DIDF RFO solicitation with Pacific Gas and Electric Company ("PG&E"), where the planned addition of direct-current fast charger ("DCFC") led to a complete revision of the service requirements for the Calflax project.[2]

More significantly, changing cost estimates for traditional capital investment projects can derail the economics and viability of deferral project bids, as experienced in the 2020 DIDF RFO of Southern California Edison Company ("SCE"). As CESA has learned, the traditional unit cost of mitigation is subject to revision as the utility conducts field verification to increase the certainty of cost estimates, measured in AACE levels. The accuracy of the cost estimate is increased as such verification activities traditional projects advance from AACE Level 5 (where actual costs can

[2] With electric vehicle ("EV") loads and DCFCs in particular becoming more prevalent over time due to the state's transportation electrification goals, this upcoming cycle should explore how such loads are forecasted and how planned investments factor into addressing distribution capacity needs. In particular, CESA was surprised to learn that DCFCs are modeled as 24x7 loads, likely due to the forecast being based on the 24x7 load service sought by the DCFC operator. However, this assumption is perplexing when DCFCs are typically taking service under rate schedules that are intended to incentivize more grid-optimized charging. DERs have great potential to defer such capital investments, which should explored in this DIDF cycle. There may also need to be further work in ascertaining long-term growth plans from EV charging operators – a broader issue that may need to be addressed outside the DIDF process.

change up to 100% from the cost estimate) to AACE Level 1 (where actual costs can more narrowly change up to 15% from the cost estimate).[3] As a result of these field verification activities, projects in SCE's 2020 DIDF RFO experienced large swings in the deferral value due to the underlying traditional unit cost of mitigation being reduced in half in some cases.

While these uncertainties are inherent to a degree in the distribution planning process, CESA believes that this current dynamic structure and mid-stream adjustments during the competitive solicitation process are completely unworkable for deferral projects, even with improvements to further streamline the DIDF solicitation and contracting process. Rather, certainty is needed for developers to find it worthwhile to make some upfront investments to compete in these solicitations, where such investments are not minimal in many cases, involving significant site development, customer acquisition, and interconnection study costs. In addition to disclosing AACE level information on planned investments and providing qualitative information about the nature of the customer and load service request of the forecasted distribution need (*e.g.*, large residential development, DCFC load service request), this certainty could be achieved with a "freeze" on cost estimates and certain forecast adjustments, and thus the deferral value, prior to the solicitation. To justify this freeze, the Distribution Planning Advisory Group ("DPAG") could identify a shortlist of Tier 1 high-potential deferral opportunities that the utilities should target for further field verification activities *prior to the solicitation launch* to provide more certainty to the cost estimate of the planned investment, leading to projects being rated closer to AACE Level 1. At the May 28, 2020 workshop, SCE explained that such field verification activities take a significant amount of time to complete, where more rigorous cost estimation is typically done

[3] *AACE International Recommended Practice No. 18R-97: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries* (2005).

closer to the need date. Recognizing this, CESA believes that such field verification and rigorous estimation processes should be prioritized for a subset of projects and conducted much more in advance, deviating from the usual utility practices. By prioritizing a smaller subset of projects for such intensive cost estimation activities, a better balance can be achieved that recognizes the utility workload. The DPAG could discuss the appropriate AACE level at which the cost freeze is appropriate and ascertain a better understanding of the utility time and resources to achieve this agreed-upon AACE level.

In summary, rather than a large number of deferral opportunities with limited or no certainty on the deferral value, CESA believes that the Commission and utilities will invite greater developer participation in the RFOs with a smaller subset of projects with certainty on the service requirements and deferral value. Even as conditions and forecasts change, other planning and procurement processes, such as in the generation capacity space, move forward with some established set of assumptions. As expressed by PG&E at the workshop, changes are not made upon contract execution, suggesting that a freeze in the cost and need target needs to occur at some point in the process in order to solicit any resource. Under CESA's conceptual proposal, this type of freeze could occur for a subset of deferral opportunities prior to the solicitation.

Otherwise, alternative models or approaches for distribution deferral may need to be considered involving, for example, average avoided distribution costs, bulk DER purchases or procurement, Bring Your Own Device ("BYOD") programs, or residual distribution service markets. Whereas the cost of planned investments can change given that utility investments and expenditures are not approved on a project-specific basis but in broad categories as part of the General Rate Case ("GRC") process, DER projects are limited to the specific service requirements and costs of the traditional planned investment, creating a situation where deferral opportunities have limited viability due to the lack of certainty.

III. THE EVALUATION OF OPTION VALUE SHOULD BE INCORPORATED INTO CONTRACTS AND SOLICITATION DOCUMENTS.

CESA is greatly appreciative of the Ruling determining that the utilities should be allowed to procure for "excess capacity" so long as they are cost-effective relative to the traditional cost of mitigation.[4] The ability to procure for such "excess capacity" beyond the minimum amount needed to address the deferral need helps to mitigate the uncertainty risk of forecast changes. In the upcoming cycle, the Commission and stakeholders should consider how to incorporate these terms in the technology neutral *pro forma* ("TNPF") contracts and solicitation documents. Specifically, bid evaluation criteria should be shared to better understand how option value will be assessed across bids. Presumably, for a solicitation with a set MW or MWh need, this option value could be assessed qualitatively in terms of project expansion potential, or more quantitatively with bids that highlight $/MW or $/MWh for the base project as well as the option value potential. However, as explained in the Section II above, this option value can only be ascertained if assessed against a firm cost estimate.

IV. STANDARDIZATION OF SCREENING CRITERIA AND PRIORITIZATION METRICS WOULD SUPPORT STAKEHOLDER REVIEW BUT CERTAIN REFORM ITEMS CAN BE DEFERRED TO NEXT YEAR'S CYCLE.

CESA agrees with the Ruling that SCE's prioritization metrics represent the best practice among the utilities[5] due to its use of more granular and quantitative scoring across the various screening criteria and prioritization metrics. Among other things, at the May 28, 2020 workshop,

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[4] Ruling at 84.

[5] *Ibid* at 38.

the utilities expressed constraints in time and resources to reach a standardized prioritization metrics spreadsheet before the start of the DPAG meetings in September 2020. Though accomplishing this is seemingly doable within the existing timeframe, CESA also understands that the utilities have each already begun their distribution planning process using their existing approaches and would otherwise be redirecting their time and resources away from other potentially higher-priority reforms in the DIDF. In recognition of these concerns, the consistent use of SCE's prioritization metrics spreadsheet represents a reform that is "nice to have" in order to facilitate effective stakeholder review of candidate projects but is likely a lower-priority item among the list of reforms.

At the same time, other standardization items included in the Ruling appear to be doable and/or an already-existing baseline requirement for all DIDF filings, including the publication of underlying LNBA data for all planned investments and candidate projects, use of common IEPR forecast datasets, provision of customer composition details for planned investments, use of 10-year and 5-year planning horizons for sub-transmission and distribution projects respectively, further qualitative information on DER-driven needs, and make all data available with redactions made upon motion by the utility.[6] Each of these reforms represent common-sense and achievable reforms in this 2020-2021 DIDF cycle that ensures a common baseline of standards and requirements for the DIDF filings.

Overall, greater standardization will make it easier to assess the nature, location, and costs of the identified grid needs and planned investments. Among the various reforms, however, CESA believes that the implementation of these reforms may be a lower priority, even though the Commission and the utilities should continue to strive for greater standardization. More robust

[6] *Ibid* at 18-20 and 22.

stakeholder review is in the interest of improving the identification of high-potential and viable projects.

V. IMPLEMENTATION OF THE FIRE-THREAT AND PSPS OUTAGE DATA LAYERS SHOULD BE PRIORITIZED AMONG THE DATA AVAILABILITY REFORMS.

CESA strongly supports the Ruling's enhancements to the Distributed Resources Plan ("DRP") data portals to increase data availability and transparency and to specifically include pre-application projects and to add layers that highlight hosting capacity availability, fire threat assessments, tree mortality data, and detailed historical PSPS data.[7] Among these areas of reform, CESA strongly recommends immediate implementation of the fire-threat and PSPS data layers to the DRP data portal due to the urgent risks of PSPS events with the upcoming wildfire season. While the connections to the DIDF process are not clear on its face, these data portal enhancements would provide major benefit to the Commission's near-term objective to mitigate the impacts of PSPS events in the upcoming 2020 wildfire season and to support the deployment of behind-the-meter ("BTM") resiliency solutions.

The Self-Generation Incentive Program ("SGIP"), for example, has recently implemented and launched the new Equity Resiliency Budget category to support the deployment of energy storage systems to low-income and disadvantaged community ("DAC") customers who either live in Tier 2 or 3 High Fire Threat District ("HFTD") zones or have experienced two or more PSPS events. Equity-related criteria and HFTD zone data is readily available to the public today, but the PSPS outage data is not currently available in an accessible manner to support the customer identification and acquisition process to support energy storage deployments. Similarly, the Microgrids proceeding (R.19-09-009) is focused on near-term resiliency solutions, where such

[7] *Ibid* at 23-24 and 31.

map data would support the microgrid development process. To make these data layers useful, the utilities should also provide this data in a more granular fashion on a circuit-by-circuit level, as opposed to the imprecise "polygons" used in 2019 for their PSPS outage maps on their website.

Given these cross-benefits with other Commission initiatives, this reform item should be prioritized for implementation as soon as possible. CESA understands that customer privacy considerations may need to be worked out before making this accessible either publicly or under a non-disclosure agreement ("NDA"). However, such issues should be worked out as soon as possible to support timely implementation.

Furthermore, CESA is generally supportive of including pre-application projects in the DRP data portal, but until the Commission and stakeholders are able to determine a procedural and assessment framework to defer the Commission-jurisdictional distribution components of those projects, this reform item may be lower priority and can be deferred to a later time.

VI. THE CONSISTENT INCREMENTALITY EVALUATION METHODOLOGY ACROSS UTILITY SOLICITATIONS IS LAUDABLE AND THE COMMISSION SHOULD EXPLORE A BROADER INCREMENTALITY POLICY ACROSS ALL PLANNING PROCESSES.

CESA applauds the Commission for ensuring a consistent incrementality approach across the three utilities.[8] Indeed, there is no reason to have a utility-specific approach to incrementality, especially as each of the utilities use the same system-level forecasts. Furthermore, the Ruling appropriately recognizes that bidders should have upfront clarity on the eligibility of their proposed resources.[9] Specifically, CESA fully agrees with the Ruling's determination that SGIP projects that provide an incremental service should be considered fully incremental given that SGIP

[8] *Ibid* at 77.
[9] *Ibid* at 79-80.

incentives represent technology incentives and are not compensating for any specific service obligation or dispatch profile. CESA supports these determinations and recommends that the language adopted in the Ruling should be memorialized in the TNPF contracts and solicitation documents of each utility.[10]

CESA also agrees with the determination made on projects compensated under the Net Energy Metering ("NEM") tariff as being fully incremental if a "material enhancement" is made to provide the distribution services solicited in the RFO.[11] However, CESA believes that this determination may be incomplete for NEM resources since the Ruling seems to suggest that only storage retrofits or additions for NEM resources that were not previously forecasted would be deemed fully incremental. There is likely some incremental value of NEM and NEM-paired storage resources depending on the forecast in terms of timing, location, and magnitude. For example, the forecast may assume 10 MW of standalone NEM resources on the grid, whereas a distribution need is forecasted that could be addressed with accelerated growth of NEM resources beyond the 10 MW forecasted (*e.g.*, 12 MW). Similarly, there could be incremental value if the forecast assumes some percentage of pairing with storage but could meet the identified distribution need if a greater percentage of pairing with storage. In such cases, there could be greater incremental value of the NEM portion of the resource, not just the material enhancement represented by the storage addition. At this time, CESA believes that the Ruling's determinations for NEM-related incrementality represent an improvement on the previous incrementality evaluation methodology used by the utilities in previous DIDF cycles, but further improvements

[10] *Ibid* at 77-78.

[11] *Ibid* at 78.

can be made at a later time to recognize the true incremental value of resources, which largely depend on the underlying assumptions and uncertainty of the forecast.

To this extent, CESA believes that the Commission should continue to explore incrementality policies across not only this DIDF process but also across all planning processes, including for Resource Adequacy ("RA"), where incrementality demonstrations represent a barrier to eligibility or under-compensation for the incremental services being provided by DERs. Whether in this proceeding or another, the incrementality issue warrants further examination to realize the full benefits of DERs and to incentivize their use for incremental grid services.

VII. VALUE STACKING AND COORDINATION OF MULTIPLE PROCUREMENT OBJECTIVES SHOULD BE ENCOURAGED AND CONTINUE TO BE EXPLORED BUT THE SHORT SOLICITATION WINDOWS SUGGEST THAT DISTRIBUTION-ONLY SOLICITATION MAY BE FEASIBLE.

CESA supports the Ruling's determination to require the utilities to provide narratives on the expected or potential value-stacking opportunities and agrees that it may be too complex to include value stacking into the prioritization criteria. With an eye toward other procurement objectives, the utilities should seek to identify the most cost-effective resources that can deliver multiple grid benefits from the same resource.[12] Granted, the utilities only have visibility into their own needs, so CESA understands that it is incumbent on the developer to pursue other revenue streams, if feasible, from other buyers of grid services (*e.g.*, community choice aggregators). However, to the degree that the utilities are aware of their other needs, such as a need to also procure for generation capacity needs, the utilities can minimally identify and describe these needs in their DDOR filings. To support and facilitate multiple-use applications ("MUAs"), CESA agrees with the Ruling that the Commission may need to more comprehensively revisit the MUA

[12] *Ibid* at 45 and 47.

framework to refine how high-value reliability services such as deferral and RA can be delivered from the same resource without preventing the delivery of either.[13]

On the other hand, CESA sees challenges with certain MUAs that may not be feasible under the solicitation and deployment timelines of the DIDF RFOs. For example, in cases where energy storage projects seek to deliver RA capacity value, developers are subject to a separate California Independent System Operator ("CAISO") deliverability study process that operates on timelines separate from the DIDF process and require three- to five-year timelines to complete the interconnection study and construction process – a timeline that may be challenging for the short lead-time windows of the DIDF. While such value-stacking projects should not be excluded from DIDF RFOs, each of the utilities should accept distribution-capacity-only offers as well as bids that offer both distribution deferral along with other value streams (*e.g.*, RA capacity).

VIII. REFINEMENTS TO CONTRACTING AND PERFORMANCE REQUIREMENTS FOR RELIABILITY PROJECTS SHOULD BE PURSUED.

CESA supports the Ruling's affirmation that the various need types should be separated out and that the DIDF process should continue to pursue reforms to enable the deferral of reliability and resiliency projects.[14] In advancing reliability projects in particular, the Ruling and the workshop discussed the IPE's recommendation that event-driven approaches may lead to DER dispatches that are ultimately determined to be unnecessary, which could be "less desirable to a developer."[15] While unnecessary DER dispatches should be avoided, CESA also believes that the day-ahead notification and dispatch structure is preferable by developers to provide certainty, in the case of storage projects, on being able to secure sufficient state of charge to deliver on the

[13] *Ibid* at 80.

[14] *Ibid* at 30.

[15] *Independent Professional Engineer SCE 2019 GNA/DDOR Report* at 53.

contingency capacity needs and/or to manage other service obligations (*e.g.*, in the wholesale market, to their host customer, and/or for other load-serving entities). Presumably, the alternative would be to subject DERs to real-time or day-of requirements to reduce the need for unnecessary DER dispatches – a dispatch model that is more challenging for DERs, even if it results in some unnecessary dispatches when the contingency need ultimately does not occur. Especially as the IPE notes that contingency needs can be low in number per year, some unnecessary DER dispatches in exchange for day-ahead dispatch notification and dispatch requirements may be preferable, though CESA understands that the IPE commented on how this may impact the $/MWh-year LNBA value. Regardless, CESA looks forward to working with the IPE to further explore this issue in the upcoming cycle.

IX. UTILITY-OWNED DEFERRAL PROJECTS SHOULD BE ELIGIBLE IN FUTURE SOLICITATIONS BUT ADDITIONAL DEVELOPMENT OF GUARDRAILS AND FRAMEWORKS IS NEEDED.

CESA supports the consideration of utility-owned projects in these deferral solicitations. If ratepayers have the potential to achieve cost savings from the procurement of DERs, regardless of ownership structure, such projects should be pursued and considered, whether as part of the regular solicitation or as part of the utilities' contingency planning. However, as the Ruling notes, it is important to ensure that forecast and planned investment details must be made equally available to third parties with a sufficient level of detail.[16] In addition to ensuring a level playing field, the solicitations must also be structured to adhere to the firewalls between the utility bidding and procurement evaluation teams. Furthermore, considering "distributed energy resources" can refer to both customer-sited BTM projects as well as distribution-connected in-front-of-the-meter ("IFOM") projects, the Commission should affirm that utility ownership should not be pursued for

[16] Ruling at 72.

customer-sited BTM projects, which represent a market segment that is already competitive and well-served by third-party market participants.

At the same time, while supportive of all ownership models to address cost-effective deferral needs, CESA believes that the limited timing available to conduct a solicitation, evaluate bids, seek Commission approval of contracts, and deploy and construct projects may make it challenging for utility-owned projects to be feasible at this time. Currently, the DIDF process is structured to provide a three- to four-year window to deploy projects from solicitation to need date, which may be untenable for utility-owned projects that would normally face extra Commission and stakeholder scrutiny to ensure a level playing field and ratepayer savings on capital investments for any solicitation involving both third-party and utility offers. As PG&E noted at the workshop, there are also considerations on the utility side in terms of structuring different products and contracts that could slow down the process. Therefore, until the current DIDF process and framework is refined to establish the appropriate guardrails and to address the timing considerations, CESA recommends that utility-owned projects should *not* be considered in the 2020-2021 DIDF cycle but be teed up for consideration in subsequent DIDF cycles. In the current DIDF cycle, however, stakeholders could still explore different pathways to identify specific need types (*e.g.*, less than three-year lead time), product and contract structures, and/or alternative solicitation structures (*e.g.*, split "tracks" of solicitations) to enable utility-owned project participation in future DIDF cycles.

X. TARIFF-BASED SOURCING MECHANISMS SHOULD BE REVIVED FOR FURTHER DISCUSSION AND CONSIDERATION.

CESA agrees with the Ruling's affirmations to the DIDF process to ensure that the utilities adhere to the six-month timeline from RFO launch to filing for Commission approval of contracts. To enable broader DER participation and possibly address some timing considerations, the

Commission should revive the DER tariff proposal ideas submitted by parties in February 2019 in R.14-10-003. The Ruling echoes these calls to explore the use of tariffs that "may help to streamline the procurement process."[17] CESA agrees, though we note that tariffs may not solve all lead time considerations as customer-sited projects also face not insignificant interconnection and customer acquisition timelines. Like with IFOM projects, success under a tariff approach also hinges on the deferral values and service requirements being established with certainty and not subject to change.

XI. CONCLUSION.

CESA appreciates the opportunity to submit these informal comments in response to the Ruling and Energy Division's request. We look forward to working with the Commission and stakeholders in this proceeding.

Respectfully submitted,

Alex J. Morris
Executive Director
CALIFORNIA ENERGY STORAGE ALLIANCE

Date: June 5, 2020

[17] *Ibid* at 11.