Comments on Staff's Report Regarding Retention of Existing Baseline Resources under Tier 2

prepared by Ampersand Hydro LLC

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Executive summary

Although Ampersand Hydro LLC ("AHL") appreciates staff effort in formulating a revised proposal regarding treatment of the maintenance tier related to retention of Tier 2 resources, AHL is concerned that as structured the proposal does not address significant concerns with the process and its potential outcomes.

Implementing a program to provide existing off-contract qualifying resources with a credit equivalent in value to the zero emissions credits ("ZECs") granted to nuclear resources would be more equitable, economically efficient, and administratively straight-forward, while being cost effective for ratepayers.

However, should the Commission proceed with the Staff proposal, AHL believes it should be modified as follows:

- Review level financial statements, rather than audit level, should be accepted as part of the streamlined filing, and independent engineering reviews should not be required for smaller capital expenditures;
- Contract terms should be for a minimum of seven [7] years;
- Forward prices should be substituted for CARIS for the initial years of the analysis;
- Appropriate management fees need to be acknowledged as legitimate to go costs;
- Intercompany allocations should be allowed based on the "lower of cost or market" rule; and
- Outstanding maintenance tier applicants should not be forced to refile in order to attain the benefit of the proposed corrections in the interpretation of go forward costs.

We discuss each of these matters in greater detail below.

Standing

Ampersand Hydro, LLC ("AHL") controls 12 small hydro stations in New York State totalling 18.7 MW with an expected annual production in excess of 70,000 MWh. AHL specializes in acquiring aging hydro stations and rehabilitating them, preserving a zero-emitting resource using existing infrastructure. All of AHL's hydro stations in New York are currently merchant facilities, relying almost entirely on wholesale energy and capacity revenues to fund their operations.

Favorable aspects of Staff proposal

While AHL believes the Staff approach is sub-optimal, there are aspects of the proposal that have merit. The ***risk contingency*** element, which the Staff proposes to be 5%, is consistent with the recognition that qualifying resources such as small hydro face two sources of revenue volatility: hydrology and price risk. Maintenance REC awards do not provide full recovery even of "go forward" costs, as the maintenance RECs are intended to "top off" market revenues. Revenue uncertainty is exacerbated by the relatively short three-year term that Staff has proposed. In this context, the concept of a risk contingency is welcome, though AHL believes it should be <u>more appropriately set at 10%</u> given the multiple sources of volatility in qualifying resource revenues.

Likewise, acknowledgement that ***cost of capital for future capital expenditures*** is a legitimate go-forward cost reflects commercial realities. No investor is going to devote money to a risky enterprise such as making a major repair to an existing facility without an expectation of return. In calculating such a cost of capital, however, Staff need to be mindful that <u>the return needs to be higher than that of the utilities that it regulates</u>, given that qualifying resources are not under cost-of-service rates: unlike utilities, qualifying resources cannot recover revenue shortfalls from ratepayers in the event of poor hydrology or lower than expected market prices.

Level of accounting statements and supporting documentation required

Staff proposals for the streamlined filing require documents that many smaller producers are not likely to have. AHL is likely not alone in not having audited financials; AHL's banks generally require review level rather than audit level financials. Entities even smaller than AHL, for example those that are essentially family operations, may have even simpler accounting standards. Requiring applicants to produce three years of audited statements may be an unacceptable barrier to submitting an application when such statements do not exist, particularly if such additional costs are not considered as part of the "to go" costs. While AHL would be comfortable if the requirement was reduced to a review level set of statements from an independent accounting firm, some owners may need alternatives even to the review level.

AHL also has concerns regarding the requirement that the applicant provide "engineering reports" to support "any" proposed capital additions. AHL believes that Staff should consider adding a materiality threshold before third party engineering reports are required, as this again adds to the cost of submission. For capital expenditures below the threshold, say those costing less than $250,000, applicants should be allowed to substitute an internal narrative prepared by a qualified individual. Requiring an independent engineering report for smaller capital expenditures would result in an additional barrier for applicants given not only the cost of such reports but also the time it takes to have them prepared.

Contract term and renewal

Staff proposes that contact terms be limited to three, albeit renewable, years. Given the extent of volatility in wholesale power prices, the unreliability of the CARIS forecasts, and the expectation that wholesale power prices may remain depressed indefinitely, three years does not provide a sufficient period in which to assure appropriate recovery of the maintenance investments. This in turn may prevent them from occurring. While AHL believes that there is an argument for the maintenance REC payment periods to match the potential life of the capital investment, and indeed NYSERDA programs related to upgrades allow for longer terms, AHL recognizes the need to balance certainty for investors against the desire to not tie ratepayers to long term contracts during periods of prolonged electricity market uncertainty. Ironically, Staff's rationale for the relatively short contract length (future market uncertainty) is precisely what creates a barrier to investment at existing qualifying resources. AHL believes a seven-year term would appropriately balance the needs of ratepayers and investors.

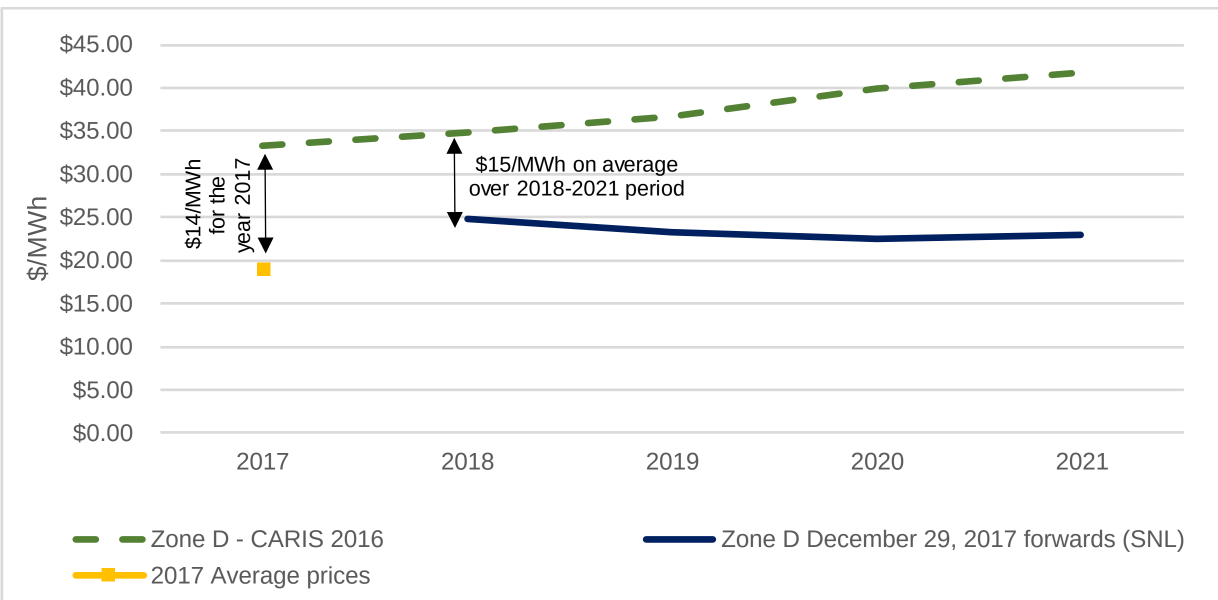
The suggestion that the contracts are potentially extendable, though helpful, may be problematic methodologically if a new application is required. If the three-year contract term is retained, resources should be allowed an automatic extension through a simplified form if they can demonstrate either that wholesale market prices have been significantly below those used to calculate the initial award or price projections for the subsequent three-year period are below those projected when the initial award was made. If such provisions are not put in place, qualifying resources face a Catch 22 in applying for an extension – the investments causing the need will have been sunk at the beginning of the first contract period, and thus will not be part of the "to go" costs, meaning that the extension period award could be zero.

Use of forward prices in lieu of CARIS

The proposal to use CARIS forecast prices instead of current forwards raises potential issues given the way in which the CARIS forecasts diverge from both forwards and market outcomes. Forward prices from third party providers are readily available and unbiased, and are less static than CARIS. AHL recommends that Staff replace the requirement to use CARIS forecasts with a list of one or more sources for forward zonal energy prices which applicants can use in their pro formas. This would allow for calculations to be made using the most recent available market information.

The figure below shows a comparison between 2016 CARIS forecast prices, market forwards, and 2017 historical average prices for Northern New York (Zone D). Given Zone D real-time prices in the year 2017 have averaged $19/MWh (about 45% below CARIS price estimates for the year 2017 - $33/MWh), it is evident that the CARIS forecast prices are not realistic, can quickly become stale, and at odds with market fundamentals. In fact, 2016 CARIS forecast values for the next 4 years (2018-2021) are on average double current electricity prices, and are on average 64% higher than the latest market forwards for the 2018-2021 period.[1] Given this divergence, awards based on CARIS may result in project failure as they underestimate true need.

Figure 1. Price comparison between forwards, CARIS and actual values



Use of intercompany allocations and appropriate allocation for cost of management

The prohibition on allocated costs is counterproductive and will likely result in higher to go costs. Staff seem to be suggesting that a single plant that pays a third party to perform back office tasks would be allowed to include such costs, but that a plant that acquired the same services from an affiliate would not, unless that affiliate produces a plant-specific detailed invoice. This is inconsistent with the way business

[1] As of Friday December 29th, 2017.

processes actually work, and it is also in contrast to the use of allocation factors for regulated entities.

For example, a single accounting department staff member may process a number of payments for multiple plants over the course of the day; on various days, the number of payments processed for one plant may be higher than for another. The holding company knows in aggregate that it is cheaper for all of the plants if this function is performed in-house, it knows roughly how many transactions there are per year per plant, and it can fashion a reasonable allocation factor for each plant accordingly. Similarly, in regulated utilities, the principle of "cost causation" is used to justify allocation of central costs across multiple regulated (and in some cases unregulated) entities. It would be inefficient, let alone impractical, if the accounting staff had to record time spent processing each payment and create a charge sheet each day by plant.

The Commission should allow allocated costs from affiliates, provided the allocation factor is explained in reasonable detail, and resulting costs do not deviate substantially from market norms as observed in other applications. Furthermore, the costs of managing small renewable resources are high; small hydro resources are among the most regulated power producers, requiring additional management attention. Management fees are a necessary part of the to go costs of such facilities.

No need to refile

Entities with existing maintenance REC applications outstanding should be allowed to attain the benefit of proposed modifications to the process of determining awards without having to refile. In some cases, such applications have been outstanding for several months, and both staff and the applicant have been working diligently on them. Requiring refiling would result in a further delay that could further harm the financial viability of the facilities.

Concluding remarks and AHL request to Commission

The reliability must run ("RMR") contract is an inappropriate analogy when considering retention of existing zero-emitting resources. Staff's continued references to the "to go" cost standard and RMR contracts are troubling for a number of reasons. First, RMR contracts are designed with the clear understanding that the resource is intended to be replaced, and that it will be replaced with something more economic. This logic is flawed when applied to Tier 2 resources. If it is Staff's intent that Tier 2 resources be forced into retirement by market prices which have been suppressed in part by New York's own market interventions, the results would be pernicious. As prior submissions by AHL have demonstrated, the cost to replace existing qualifying resources with new Tier 1 resources is significantly higher than it is to pay a fair price to existing Tier 2 resources to remain online.

Furthermore, there is insufficient evidence to suggest that entities eligible for ZECs have been held to a similar "to go" cost standard. Such a standard would force any plant with debt into bankruptcy, with uncertain consequences regarding its future operation as post-bankruptcy investors require net income higher than zero unless substantial compensation to management is involved in the to go costs. It is doubtful owners of ZEC-eligible resources would have accepted such a minimal level of compensation.

Staff confidence that "programs like CCA and other third party voluntary purchases are available" is inconsistent with practical realities; search costs are high for small producers to even uncover CCA opportunities, and few exist. Utility inertia makes net metering difficult; in some cases such arrangements can take over two years to implement. Voluntary REC prices are negligible, markets are illiquid, and many corporate buyers demand "additionality" which makes existing resources ineligible.

Finally, as AHL has emphasized repeatedly, failure to provide ZECs to entities which provide a similar zero emissions product presents a taking. The ZEC program was clearly justified in terms of the social cost of carbon; zero emitting attributes are an additional product produced by small hydro generators that requires compensation regardless of their financial health.

Staff's proposal continues to give the impression that they would rather have existing renewable resources exit that be provided fair compensation for their attributes. Expanding the ZEC program to include existing zero-emitting resources would allow the Department to focus its efforts on more material matters to ratepayers rather than reviewing potentially as many as 141[2] maintenance REC applications, some for awards of less than $100,000 spread over multiple years. In some cases the cost of having Staff perform the review almost certainly approaches the amount of the reward.

AHL requests the Commission to expand the ZEC program in lieu of Staff's proposal to address maintenance tier issues; if Commission is unable to do so, AHL requests at a minimum that that Commission incorporate AHL's proposed modifications to the Staff proposal.

[2] Number of applications estimated based on existing eligible Tier 2 resources. Source: *Ventyx, Energy Velocity Suite.* The "141" number originates from the following considerations. We looked at all renewable technologies (wind, biomass, and run-of-river hydroelectric facilities in New York state) that entered commercial operation prior to January 1, 2003. All municipalities and state facilities were excluded from the sample. Only run-of-river hydroelectric facilities of 5 MW or less were included in the sample. This "141" number however, might overstate the potential number of qualified Tier 2 resources that could file a petition with the DPS for maintenance resources, as in our search parameters we did not account for facilities' financial situations.