September 28, 2017

Site C Panel,
British Columbia Utilities Commission
c/o Mr. Patrick Wruck, Secretary

Dear Commissioners,

The undersigned are pleased with the immense amount of work the Commission and its consultant Deloitte have managed in a very short time and look forward to many of the Panel's questions being answered in the coming weeks. In that spirit we offer the following (non-exhaustive, but potentially important) comments on the preliminary report.

(1) It would be helpful if, in accord with standard regulatory practices, the Commission could set some ground rules for BC Hydro and intervenors. These assumptions would be critical for assessing impacts on revenue requirements and rates, key parts of the Commission's remit. For instance:

- Uniform rules for valuing proposals should require explicit costing of equity risk, whether borne by a proponent or shifted to some other party. The BCUC-allowed returns to equity for Fortis and BC Hydro might be the norm for all proponents. (We note in passing that the hurdle rate for World Bank financing of energy schemes is an expected rate of return on equity in excess of 12 percent, and has historically averaged 14.7 percent.) Asserting that these costs are zero because BC Hydro can shift them to taxpayers does not mean that equity, as a buffer against risk and a reward for excellent planning and execution, does not exist.
- Financing terms and hence project amortization, especially those which presuppose the indefinite continuation of today's anomalously low rates, may not be longer than those commonly available in commercial corporate markets: 30 years, say.
- The yield curve should, by 2024, be assumed to approximate the long-term average of the pre-2007 era—that is, with long low-risk rates on the order of 4 percent real.
- Inflation should be assumed to be 2 percent indefinitely.
- For comparative purposes, all projects should include in their capital costs the present value of eventual decommissioning and site remediation, as required by U.S. GAAP (Codification Topic 420 – ASC420)

(2) There appears to be some confusion between DSM and price-driven conservation or substitution. BC Hydro argues that almost everything falls into the first category, so that an assumption of -0.05 for price elasticity for the residual is reasonable. No one will make any changes in electricity consumption patterns, it is argued, unless induced to do so by an expenditure by BC Hydro. Rate structures such as time-of-use pricing cannot be used to shape demand. Separately, the Commission appears to say that changes in codes and standards are not legitimate components of DSM (Preliminary Report, Annex A, p. 20).

However, In the U.S., the use of rates to shape loads has been the dominant form of DSM for a generation. (Charles River Associates, *Primer on Demand-Side Management*, World Bank, Washington, D.C., February 2005). Price elasticity is analytically separated from active measures like load-shedding agreements, codes and standards, and subsidies for conservation investments, with the result that elasticity coefficients on the order of -0.40 are the norm, with DSM *en sus*.[1] The *Clean Energy Act 2010* includes (s. 2(b) and s. 1, "demand-side measures") rate structures not specifically proscribed which help manage demand, and encourages the use of codes and standards.

The billion-dollar investment in smart meters has large unexploited potential for demand-side management, especially through time-of-day pricing, particularly now that Residential has become the largest revenue earner of the three main classes.

(3) The load forecast allows 2,662 GWh for LNG from 2024 onward, which appears (RRA, p. 3-5) to be the simple sum of requests for power in proponent plans unreduced, as other components of the forecast are, for their probability of occurrence. We believe that probability to lie between 0 and 10 percent, given the glutted state of world LNG markets and growing supplies from lower-cost jurisdictions. These have resulted in recent cancellations on B.C.'s North Coast. [Two of us (Chiesa and Finn) have considerable professional experience in the world-wide LNG industry, and especially (Finn) the three LNG proposals (Woodfibre, Fortis/Tilbury and LNG Canada) included in BC Hydro's forecast.] LNG, should it be developed, would normally generate its own power, and its proponents might possibly even wish to arrange the sale of surplus power.

(4) An assumption that it would be desirable to scale back the contribution of IPPs who are compliant with their current contracts because of high prices is unsafe. At contract renewal time, their debt will have been paid off. Subsequent contracts would be expected to be based on dramatically lower costs. There is a hint that BC Hydro is already negotiating on that basis, a good thing. The IPP community currently supplies about 30 percent of the net load, and pays taxes to boot. Put another way, yeaterday's high prices are what we have already paid for the opportunity to access these sources at lower prices for decades to come.

(5) Elsewhere on the supply side, we commend the Panel for raising the question of whether the Columbia River Entitlement should be considered as part of assured supply through the medium term, here defined as the rolling 10-year guarantee under the Treaty. Undertakings of this magnitude often require an off-take agreement from a

[1] https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf

nearby utility which agrees to buy power over an initial term until the proponent utility can fully digest its need and cost. This was the solution Premier W.A.C. Bennett adopted in 1964, taking advantage of the US need for power for the first three decades of Treaty operations. But conditions have changed. The US does not need the power at present, as shown by the prices reported in Mr. McCullough's Sept. 25 report to you. Should BC Hydro need more power, it can both reduce the 3700 GWh it currently exports and retain an increasing fraction of its Entitlement. The very high losses of the initial years of Site C operations can be completely avoided.

(6) On p. 106 of the Preliminary Report, there is an assumption that if Site C is completed on time and on budget that the net incremental cost can be accommodated within an average 2 percent (inflation only) annual increase in BC Hydro's rates after 2024:

The total revenue requirement from F2018 to F2094 is estimated as follows:

> *In the Base Case, rate increases are assumed to increase by 3.5 per cent in fiscal 2018, 3.0 per cent in fiscal 2019, and by 2.6 per cent each year from fiscal 2020 to fiscal 2024, consistent with the 10 Year Rates Plan. For years after fiscal 2024, BC Hydro has assumed for the purposes of this analysis annual rate increases equal to inflation of 2.0 per cent.*

The Panel assumes this to mean that BC Hydro is expecting the cost of Site C, implemented in 2024 at a cost of $8.335 billion, to be reflected in the total revenue requirement calculated on the basis above. Thus, it follows that if Site C were to be delivered in a year other than 2024, or for a cost other than $8.335 billion, there would be cost impacts to ratepayers.

Neither BC Hydro nor Deloitte has made this statement. Responding to the directives and other political directions of the previous government, BC Hydro has been coy about future net costs of the project. It has told the Commission only that these would be proposed in a future rate application, presumably for fiscal 2024. In fact, the Panel's assumption makes sense only under conditions of rapidly increasing the already out-of-control debt of BC Hydro, which has tripled from $7 billion to $20 billion in just ten years.

In sum, the Commission's assumption that the net cost impact of Site C could be accommodated, via the Ten-Year Plan's 2.6 percent annual increases and zero real increases thereafter, appears to require re-thinking, unless a continued and sharper deterioration in the financial condition of BC Hydro through borrowing is contemplated. As its present debt:equity ratio is approximately 4.5:1 as opposed to the target 1.5:1, not counting the burden of regulatory assets, this seems anomalous. Even BC Hydro says that the 2.6 percent rate increases will not accommodate Site C. (BC Hydro also says that the $1.58 billion in the Rate Smoothing Regulatory Account will be eliminated by 2024 within the 2.6 percent cap, a true loaves-and-fishes miracle.) We would rather see BC Hydro present to the Commission a clear picture of future power rates—incorporating cost inflation, Site C, a return to a healthier 1.5:1 debt:equity ratio, and a recapture of the $5.9 billion regulatory accounts.

(7) This raises a last point. Section 3(b) of the Terms of Reference asks for an assessment of the costs to ratepayers of suspending or terminating Site C, but not the costs of completing it—even though S. 3(a) asks for the implications of all three

alternatives. Early-year losses would have to be added to capital costs. “Implications” presumably includes an estimate of the rates that would be faced by major categories of ratepayers. And circling back to our first point, this would seem to require some sort of credible long-term base case. As BC Hydro will not provide it, the task falls to the Commission.

With sympathy for the task ahead, and in faith that our Commission is up to the task, we are

Sincerely yours,

Eoin Finn

Harry Swain

Mauro Chiesa

Roger Bryenton