March 29, 2018

UCA Position on the 12 Coincident Peak Transmission Cost Allocation Issues

Introduction

1. The UCA was an active participant in the facilitated stakeholder consultation session hosted by the AESO on March 12, 2018. After listening to the various presentations made by the AESO, AML, ADC, DUC, IPCAA, and the CCA, on that occasion, along with responses to pertinent questions, the UCA believes that a system economic problem has developed that is exacerbated by the transmission cost allocation procedures currently used. This problem requires immediate reconsideration and development of corrective measures that will reach beyond a simple adjustment to the 12 Coincident Peak (CP) transmission cost allocation methodology.

2. The 2005 transmission regulation relieved generators of any responsibility for transmission wire costs whereas previously one half of total transmission wire costs had been allocated to them. This change in the regulatory framework exposed load customers directly to the full cost of transmission wires comprising what is defined as the “bulk” system. This also removed effective price signals for new generator location that were based on the cost of transmission reinforcements necessary to accommodate them.

3. An alternative attempt to use energy loss factors as a price signal for generator location has been the cause of much confusion and dispute for many years. Marginal loss factors are not effective as a price signal. They are highly unstable, and bear little relationship to the costs of expanding the transmission system to accommodate new generation.

4. The more recent completion and addition to rate base of two HVDC lines added substantially to the costs of the bulk system that can now only be recovered from net load customers.

5. Given the escalation of transmission wire costs that must now be borne solely by load customers, it is not surprising that serious concerns have been raised over the cost allocation procedures in circumstances that now invite uneconomic transmission bypass and suboptimal developments in the absence of integrated generation and transmission system planning and efficient price signals.

6. As described in the UCA's March 9, 2018 Submissions ("March 9th Submissions") such reconsideration must include what transmission line elements comprise the definition of "bulk" versus "regional" transmission subsystems, as well as the precise form of CP or other allocator used.

The Position of the UCA

7. The interest of the UCA is to find an approach that will address the identified problems of transmission cost allocation without causing hardship to any user of the transmission system. The approach should also provide better long term price signals for efficient development of a reliable electricity supply system that is affordable for all customers, especially given the changes that the electricity system is facing today.

8. To be clear, the UCA is not motivated by a desire to shift costs from one class of transmission customer to any other class. Should a cost allocation approach be found that better addresses the identified problem but also causes a significant cost shift to a particular group, the UCA would urge that a long term mitigation strategy be adopted for existing customers.

9. For instance, the UCA is sensitive to the concerns of the Energy Intensive Trade Exposed (EITE) industrial customers (i.e. members of ADC/DUC/IPCAA) who rely on control of monthly coincident peaks in order to avoid some transmission costs. It has been recognized historically in Alberta that the reduction of peak loads that are coincident with peaks of generation reduces the costs of aggregate generating capacity required, and is of value to the overall system.

10. It is not clear to the UCA however that such peak "clipping" at times of generation stress results in any material reductions in bulk transmission costs, as the elements of this transmission subsystem are designed to meet very different stresses and stability criteria than that of aggregate generation capacity.

11. In terms of signaling behavior that provides value to the system, and the mitigation of any potential shift of wire cost allocations, it is important that reconsideration of transmission cost allocations be conducted in concert with the development of the generation capacity market. If transmission tariff adjustments reflecting more appropriate cost allocations were to be made coincident with the introduction of a credit for reducing the level of aggregate generation capacity, then EITE customers would not be disadvantaged by refining the allocation of transmission costs to better reflect cost causation.

12. The UCA would like to remind all parties that cost allocation is a distinct and separate process to rate design. They are not to be treated as an identity and changes in cost allocation may not always translate directly into tariff changes.

13. The principles of James Bonbright that may conflict are intended to be considered as a whole. It is not helpful to consider Bonbright principles as a set of "weighted" factors to be applied mechanically to the results of a cost allocation study. Any single Bonbright principle (such as rate stability) may at times be determinative and override an entrenched consideration such as exactly recovering the cost of service by class.

Information that will assist in evaluating Alternative Allocations

14. In its March 9th submissions, the UCA outlined concerns with the current definition of bulk system and the specific version of 12 CP allocator in use. In summary the current allocation approach was developed for a previous vertically integrated monopoly structure where the allocation of generation costs was paramount, and errors made in the allocation of smaller transmission costs did not have the consequences that they now have for a desegregated structure where generation development is determined by market forces and transmission costs are driven as much by the locational decisions of independent generators as they are by traditional load customers.

15. In order to better reflect cost causation in the current desegregated structure as well as mitigate the price signals problems noted by others, the UCA has suggested redefining the division between bulk and regional systems as well as a broadening of the application of the CP allocator to encompass more hours matched to the load duration curves and coincidence with bulk transmission system elements. To inform this discussion and the exploration of transmission

cost causation and improved definitions of transmission subsystems, the UCA would like to receive responses from the AESO to the following requests for information:

a) Please identify and explain any potential cost reductions in the **bulk** transmission system (or any elements thereof) as a result of POD (Point of Delivery) load reductions made during the 12 hours coincident with monthly peak aggregate generation without making any reductions to the NCP (Non-Coincident Peak) loads at the same POD.

b) Please identify and explain any potential cost reductions in the **bulk** transmission system (or any elements thereof) as a result of reductions of NCP load at any POD.

c) Please identify and explain any potential cost reductions in **regional** transmission systems (or any elements thereof) as a result of POD load reductions made during 12 hours coincident with peak aggregate generation without making any reductions to the NCP loads at the same POD.

d) Please identify and explain any potential cost reductions in **regional** transmission systems (or any elements thereof) as a result of reductions of NCP load at any POD.

e) Please provide a table indicating the changes to cost allocations that would result from the changed definition of bulk system, and the use of 12 hourly averages to determine each monthly CP as requested in the UCA's March 9th Submissions.

f) Would the UCA proposed change to bulk system definition referenced in (e) above change any of the responses to questions a) through d) above?

g) Please identify and explain your understanding of the potential cost reductions (in MW) of aggregate generation capacity that could result from POD load reductions made during the 12 hours coincident with peak aggregate generation but that do not reduce NCP loads at the same POD.

16. In addition, the UCA would be appreciative if the ADC/DUC/IPCAA group could provide some analyses of the bill increases that would be incurred by the recently suggested changes to transmission cost allocation assuming that these would translate into changes in the tariff and/or billing practices. Could ADC/DUC/IPCAA differentiate between bill increases that could result from CP to NCP allocation

from the bill increases that would result from a change from the billing of net loads for owners of BTF (Behind the Fence) generation to the billing of gross loads?

Process and Timing

17. While the UCA considers the transmission cost allocation problems identified in this and other submissions to be serious concerns that require both thorough and immediate study, we also recognize that an adequate and comprehensive study will take some time.

18. The UCA does not wish to unnecessarily delay approval of the AESO's current tariff application. It is for this reason that we have requested sensitivity studies and more general information that could all be completed and provided relatively quickly and without delaying the tariff application.

19. Comprehensive studies that may be necessary to resolve these cost allocation issues could be completed in parallel with the tariff process on the understanding that they will be completed in the same timeframe as the current application and will then inform future tariff applications. In the UCA's view, it is important that the Commission direct a specific schedule in this regard so that momentum is maintained on the important initiative to analyze and address the identified system problem.