OEB COST ALLOCATION REVIEW

Allocation of Joint Demand-Related Costs

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SUMMARY

NCP v. CP

There are two common methods for allocating joint demand related costs:

1) Non-coincident Peak: The sum of the peak demands for a class (regardless of time of occurrence)

2) Coincident Peak: The demands of any customer class at the time of the distribution system peak

Use of Non-Coincident Peak

- Staff and advisory team agree that Non-Coincident Peak should be the main allocation methodology for joint demand costs

- Rationale: distribution facilities are closer to the customer and are sized to meet the class's maximum demand and not the aggregated coincident demand of the distributor

Use of 1 Class NCP Accepted

- Advisory team favours use of 1 Class NCP, as the standard Non-coincident Peak allocator, on grounds it best reflects cost causality

No role for 12 NCP?

Advisory team recommended against use of 12 NCP as an alternative

- discussed seasonal customers as example, but rejected use of 12 NCP to "smooth" results

No Role for Customer NCP?

- Texts make reference to possible role for Individual Customer NCP

- However advisory team discussions concluded premature for present filings, as:

- there were differing accounting treatments of account 1855
- the account has only been in existence for 5 years
- there are different policies with regard to point of demarcation

Specialized Use of CP

- Staff Paper proposed Co-incident Peak be used to allocate distribution demand-related assets that were designed to meet the total system peak (i.e. facilities designed giving full consideration to the diversity inherent in all loads served)

Where use of CP appropriate?

- Staff and advisory team suggest CP should be applied where asset solely designed to meet the distribution system's coincident peak (otherwise, use 1 Class NCP)

- expected to be uncommon in practice (must examine how asset actually used)

Future Issue: Specific Illustrations of Appropriate Use of CP

Specific examples of where use of CP appropriate were discussed with advisory team and will be finalized later:

- For example, a substation that serves all of a distributor's load, and associated incoming subtransmission lines (but 1 NCP to be used where multiple substations existed)
- Others? – account 1815 (transformer station equipment above 50 kV), subtransmission

Future Issue: Use of CP for Specific Accounts

Advisory Team has started to identify specific USoA accounts for which CP may be preferable

- appears rare to identify an account (e.g. 1815) that should be allocated solely by CP

- Several accounts can be identified (e.g. 1835 – overhead conductors) may be appropriate to subdivide and allocate by both CP and NCP

Use of 12 CP

Staff and advisory team discussed use of 12 CP as the “default” CP allocator

- same approach as used by FERC for U.S. transmission filings

Use of 1 CP and 4 CP

Staff, consultants and advisory team examined FERC materials an developed tests as to when use of 4CP or 1 CP to be used in lieu of 12 CP

- for example, use of 1 CP proposed where the distributor has a pronounced peak
- potential “free-rider” problem noted in case of streetlights and summer–peaking distributor

Measurement of Class Peak: 1 hour

- There have been various prior proposals to lengthen to deliberately add stability

- Staff and advisory team suggest follow the most common method and use the single peak hour during the year

Future Issue: Adjusting for Line Losses

- Staff Paper proposes adjustment for lines loses
- Cost allocation references suggest :
  - role for demand and energy adjustment
  - differing line loss adjustment for subtransmission v. primary v. secondary

Appropriate line loss adjustment for Ontario to be further discussed (for example, will discuss use of approved 2006 EDR line loss figures)

Future Issue: Voltage Adjustment

Staff Paper proposed adjustment based on customer delivery voltage to better reflect cost causality

- Impact would be to exclude certain customers (e.g. large users) from the allocation of secondary voltage lines and line transformers since they do not use such assets

Primary v. Secondary: Implementation Issues

- Advisory team has discussed various potential definitions of "primary" v. "secondary"
- Specific definition remains to be finalized
- Advisory team may also make suggestions for potential USoA changes to facilitate future cost allocation

Primary v. Secondary: Role for Expert Judgement

- It is challenging to break out accounts between primary and secondary as current USoA does not require that level of detail

- Advisory team suggested asking distributors to use their own expert judgment and implement a primary v. secondary adjustment

- During 3rd phase, Board's consultant to work with advisory team to create useful guidance

Future Issue: Treatment of "Subtransmission"?

- During advisory team discussions, some parties suggested the voltage adjustment to allocation of demand costs extend to "subtransmission"
- Before can implement suggestions, must define "subtransmision" (initial advisory team discussions did not resolve)
- subtransmission issues may arise elsewhere

Underground v. Overhead Distinction?

Some cost allocation references propose a distinction between treatment of overhead versus underground assets

- Advisory team examined and concluded premature to implement this refinement

  (e.g. there are likely no cost details or voltage details at a feeder level to break out OH and UG in a meaningful manner for cost allocation)