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Comments by James Adcock on UE-191023 and UE-190698 CEIP Rulemaking
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Let's put the 2030 80/20 requirements in some perspective. According to EIA data about 10% of Washington State generation in recent years comes from Natural Gas, and about 5% from Coal -- for a total of about 15% -- already less than the 20% requirements of 2030! I'm not suggesting that this is all there is to it -- I'm just saying let's put these requirements into some perspective! And even then much of the current Natural Gas generation is for export!

Why does this matter? Let us examine the Utility Analysis of the use of RECs. CETA says that RECs until 2045 can be used for 20%. (RCW 19.405.040) Utility Analysis is that means RECs can also be used for the other 80% -- because the legislature didn't say that they couldn't.

Following-along this line of Analysis: CETA says that RECs after 2045 can be used for 0%. (RCW 19.405.050) By Utility line-of-reasoning then, what that means is that RECs can actually be used for the "other 100%" -- because the legislature didn't say that they couldn't.

But strangely enough Utilities shy away from this portion of their analysis -- presumably because even they could not stomach their "Analysis" opposing the clear language in RCW 19.405.050(1)

So, in summary, the entire Utility Analysis fails -- 20% means 20% -- and not an additional 80% nor 100%. Only 20% can be filled with RECs -- and those RECs have to be "real RECs" corresponding to CETA definition -- not "fake RECs" -- "RECs In Name Only" -- that might be issued in some double-counting-scheme state.

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When is a REC not a REC?

CETA has a clearly stated definition of what a "REC" is. If some other not-Washington-State jurisdiction offers something they call a "REC" but that doesn't match the strict CETA "no double-counting, including no double-counting of government mandates" definition, then for purposes of CETA compliance it is not a "REC" but rather a "RECINO" -- a "REC In Name Only." Commission must not allow the use of RECINOs -- to do so is to ignore the definition of a "REC" in CETA.

There is at least three parts to meeting CETA's strict REC requirement:

1) If a utility buys a REC, then they must guarantee that the REC is not part of a "double-counting scheme" -- and by CETA definition a "REC" -- actually a RECINO -- from a jurisdiction which does not require retirement of RECs corresponding to government mandate -- IS engaging in a double-counting scheme. It should be obvious what is going on here:

Some other state(s) while pretending to "go green" are actually trying to get Washington State Ratepayers to pay for *their* "greening" process instead of paying for Washington State's "greening" process! If a Washington State utility were to buy such RECINOs then Washington State ratepayers are getting ripped off -- they are not getting what they are paying for -- they are not "greening" Washington State, but rather (say) paying for some other state's [California's] mandates.

2) If a Washington State utility retains a REC, but then sells the *unspecified* electricity into another state, the utility is required to do so under a contract that guarantees that the purchaser will make no-environmental-claims-whatsoever about that *unspecified* electricity. For example, if the purchasing-state were to allow those-state's-utilities to claim that the *unspecified* electricity came from a Wind Farm -- that would be an "environmental claim" resulting in double counting. Or if the purchasing-state were allow the purchasing-utility to count the emissions rate of that electricity to be zero-tons per megawatt -- or even significantly lower than 0.4 tons per megawatt -- again, that would in fact be an "environmental claim" which would constitute "double counting" in violation of CETA rules. And in the process that claimed "retained REC" would actually have become a RECINO. This must not be allowed.

3) If a Washington State utility were to buy a REC out of state -- one that really is a "REC" and not a "RECINO" -- there is still the problem of the "use" definition -- it would have to be shown that the power was plausibly "used" by the Washington State utility. Contrary to Utility claims electricity *does not* flow Willy-Nilly wherever it wants within the Western United States. Rather, most electricity wants to stay close to home most of the time -- and this is not just due to the high costs imposed by "Wheeling." Rather, electricity wants to flow the path of least resistance to load, and more distant load -- in far-flung Western States -- has much greater transmission resistance (and losses due to that transmission resistance.) Which is why more-or-less all States have their own generation, and then rely at in-part on long-distance transmission for balancing and reliability. The clear exception to this is the strong AC/DC interties from Washington/Oregon to the suburbs of Los Angeles. IF -- and ONLY IF -- California could clean up their "RECINOs" turning them into real RECs [by CETA standards] then California could reasonably consider an actual REC "trading partner" to Washington State utilities. So, as a practical matter, I would suggest that the "trading regions" qualifying for "RECs" for CETA purposes -- and only if it can be clearly shown that that state's "RECs" really are RECs and not RECINOs -- that those trading partner states be restricted to the those portions of traditional "Columbia River Basin" states recognized as being part of the "BPA region." And that California only be added to this list of qualifying regions IF and ONLY IF California cleans up their RECINOs to turn them into real RECs [by CETA standards.]

Of course, if other WECC states were to clean up their RECINOs turning them into RECs -- and were to clearly engage in "REC Trading Partner" legislation in conjunction with matching Washington State enabling legislation -- then and only then should we accept such state's RECs.

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The Role of BPA

Utilities try to ignore the important role that BPA needs to play in all this -- presumably because Utilities prefer to buy or build new much-more-expensive facilities rather than purchase from BPA those capabilities which BPA is required by-law to sell to Columbia-River-Basin utilities -- not just COUs but also IOUs -- and at below market prices! The Northwest Power Act of 1980 requires BPA to sell all utilities (with COUs getting preference) three different kinds of power:

1) Bulk Power -- no need to continue to sneak Coal Power into Washington State using fraudulent "one month" contracts of "unspecified" power -- those contracts being framed falsely simply to avoid the clear intent of law.

2) Peak Power -- no need to build any more NG Peaker plants when you can buy this peaking capacity from BPA instead!

3) Storage -- yes the 1980 Power Act even specifies that *Storage* is a product that BPA must sell to utilities! So, for example, if utilities ask BPA to smooth out the variable power from Wind Farms, by providing short-term storage of that Wind Farm output, then BPA is required to sell utilities this capability -- and to do so at below-market prices.

As part of their CEIPs and RFPs utilities must ask BPA to provide these capabilities -- at below market prices as required by law -- and Commission and Washington State Government needs to help in general: by putting pressure on BPA to actually sell these capabilities, to our utilities -- at below-market prices! Not just some kind of fake lawsuit payout so that BPA can falsely continue to prefer Californian buyers.

Let us be clear: Currently BPA is sending about 7 Gigawatts of peak power daily down to California. That's the same as 70 New 100-Megawatt Natural Gas Peaker Plants! Or about 280 25-Megawatt battery storage plants.

How crazy is that??? And Ratepayers are expected to pay to build this stuff rather than just purchasing it from BPA??? Utilities and BPA need to start working together effectively. To do so is required by law.

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Response to Questions for Consideration:

Q1: Do you agree with Staff’s interpretation of RCW 19.405.060(1)(c) that Commission approval is contingent upon the utility justifying and supporting each specific action it takes or intends to take, including providing the business cases supporting each specific action identified in the CEIP?

Yes, because otherwise utilities can fail to meet CETA requirements -- such as actually getting to 80/20 by 2030. Or by wasting ratepayer monies -- while at the same time claiming those wasted monies are applicable to the "2% offramp."

Q2a: Does the Commission have the authority to require utilities to provide funding to support equity participation such as intervenor funding or direct payments to advisory group members?

If in the Commission's opinion a utility's actions, or planned course of action, does not actually, or will not actually, meet the stated equity requirement -- of actually including all ratepayers in an equitable way in all benefits -- then Commission must pro-actively require a different or additional course of action to ensure that all ratepayers fairly benefit. No Longer can the utility say "Gosh we tried -- but we just couldn't reach that class of ratepayers." Rather: The Time for such Excuses is *Over.* You can no longer just "Cherry Pick" the wealthy-early-adapter "Tesla Neighborhoods" and then leave the low-income neighborhoods out of the loop. In particular: weatherization needs to be made available to all households. The time for utilities to say "that low-income neighborhood is just too hard -- it's needs are too great -- so let's just skip it!" -- that time is OVER!

And if utilities can't do it or won't do it, then Commission should require the hiring of outside agency to do this work.

Q5: In draft WAC 480-100-660(4)(c), Staff proposes to require the utility to update the verifiable inputs of the alternative lowest reasonable cost and reasonably available portfolio (baseline portfolio). Please respond if the utility should be required to update the assumptions in its baseline portfolio when reporting its actual incremental costs, or if it should not.

Response: The utility should be required to update the assumptions in its baseline portfolio. The legislature has already accounted for the natural variability in the utility industry, including for example fuel costs, by providing a four-year averaging window, during which time a utility can actively manage its response to meet the 2% [or more] year-over-year increase requirement. This 2% is a minimum, it is not a maximum. It does not prevent a utility from spending more than 2% -- say 2.5% -- in order to offer a margin of safety to make sure the requirements are actually met -- including natural variabilities in the utility business. Commission should support such additional reasonable planning margins (say 2.5% instead of 2.0%) to allow utilities to meet the 2% -- or more -- off-ramp requirements with reasonable certainty.

Q6: The Commission is considering two alternative interpretations of the incremental cost of compliance option in RCW 19.405.060. First, both interpretations find the Directly Attributable Costs of compliance by finding the difference between the RCW 19.405.040 and RCW 19.405.050 Compliant Portfolio and the Baseline Portfolio.

Response: The "0.5%" interpretation would imply that when the legislature says 2% they actually mean 0.5% -- wouldn't it have been easier for the legislature just to have said 0.5% if they meant 0.5% ?

Reasonable estimates of the increase in rates to support zero emissions -- for the highest emissions utilities -- is a cumulative 10% increase in rates. See for example NREL studies over the last decade. In addition, to "sanity check" this 10% assumption please note that utilities currently charge "100% Green Option" customers about an additional 10%.

So, if Commission were to choose the 0.5% interpretation, how is that actually going to play out with the highest emissions utilities? I suggest the following:

The largest-emitting utilities will then have an incentive to foot-drag, engaging in mere "windows dressing" during the no-offramp compliance period prior to 2030. While they could be expected to increase revenue by 10 x 0.5% during this time period, I suggest they will only do half of this: 2.5% -- it's not that they don't have compliance requirements during this period -- they do: The law clearly requires them to get to 80/20 by 2030 *PRIOR* to being able to make use of the "2.0%" off-ramp. But, I believe utilities will avoid this requirement by playing games -- avoiding reasonable and necessary investments prior to 2030 -- because the 0.5% "penalty" [actually: alternative compliance] requirement is so "soft." And such a soft "penalty" [actually: alternative compliance] will incentivize utilities to constantly foot-drag and game-plan against Commission for the entirety of the next 25 years -- and thereafter. Whereas in comparison the 2.0% interpretation clearly states: "Get On With It. It will not benefit you to continue to play games!"

In any case, then after 2030 utilities will need to raise revenue another 7.5% at the 0.5% a year rate, which will take them another 15 years -- which means until 2045. But does that mean they will have accomplished 100% clean -- or does it mean that they will have only accomplished 80/20 by 2045 -- 15 years too late? And in any case, what happened to the clearly stated requirement to get to 80/20 by 2030? Has that not fallen by the wayside? The law clearly states that you have to get to 80/20 by 2030. It does not say that you can ignore this 80/20 requirement and then substitute a 0.5% off-ramp requirement instead.

So I believe a 0.5% interpretation has the practical effect of delaying clearly-stated 2030 80/20 requirements until 2045. Thus I believe the 0.5% interpretation is a mistake -- because such an interpretation will defeat the clearly-stated 2030 80/20 requirements in the law. Thus the "2.0%" interpretation not the "0.5%" interpretation is the correct one -- the interpretation which in practice is consistent with the rest of the stated goals and requirements of CETA.

Please note the 2.0% interpretation *does not* require a utility to actually spend 2.0% -- rather it requires the utility to actually meet the stated intent of the law -- because doing so will cost less than 2.0% -- so "No More Foot-dragging -- Do It!" -- but if there *is* some kind of utility screw-up then you still can recover from it -- by investing 2.0% a year in "catch-up" investments. So it is a "penalty" -- but still not a huge penalty -- if you screw up and fall behind on your requirements.

So I believe the 2.0% [not 0.5%] interpretation is clearly required to implement the intent of the law: Which is that utilities actually must meet the stated 2030 and 2045 requirements, and that the 2.0% off-ramp is only there as a catch-up provision in case utilities make honest mistakes -- and not 25 wholesale years of "foot-dragging" !

Thank you for your consideration,

James Adcock, Electrical Engineer