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Philip Fine, Ph.D.
Deputy Executive Officer
South Coast Air Quality Management District

21865 Copley Drive
Diamond Bar, CA 91765

Dear Dr. Fine:

From years of experience as an electric and gas utility planner I have a couple of concerns with the modeling shown in the NEAT Working Group Meeting #4 slide deck and some recommendations.

Dr. Marc Carreras-Sospedra's slide 37 says:

> "We assume changes in electricity will be met by the marginal grid
> For California, we assume marginal electricity is generated from dispatchable units, which are NG units "

Reflecting Renewable Portfolio Standards

I am concerned that this ignores Renewable Portfolio Standards (RPS) policy (or Load Serving Entity LSE policies that exceed RPS [e.g. CCA policies]) that compels LSEs to procure renewable resources equaling minimum defined fixed percentages of annual electricity sales.

In a case with more electrification, there would be an increment of added electric load in various hours throughout the year and that would compel procurement of an increment of renewable generation amounting to the RPS percentage of the increment of electrification load.

For an example territory striving toward a 33% RPS requirement, this results in (on an annual basis) each 100 MWh/year of added electrification load being met with at least 33 MWh of renewable generation and at most 73 MWh of gas fired generation (67 MWh for the maximum allowable amount supplied to customers and 7MWh to cover 7% average transmission losses).

In general, increases in electricity usage should be met by no more than (100% minus RPS% minus 7%) fossil fired generation to conform with state RPS policy.

For LSEs choosing to surpass RPS minimum renewables policies; their maximum NG fired plant utilization would be further reduced by their self-selected Renewable Content Policy (RCP).

Example for an LSE with an 80% RCP: A 100 MWh increase in annual sales for electrification could at most result in NG fired generation of 27MWh (100 MWh delivered minus 80 MWh provided by renewables plus 7 MWh of unspecified coverage of transmission losses assumed to be covered with marginal gas fired units).

The examples apply to annual results and individual days will have results above and below the annual figures as daily resource mixes fluctuate around the averages.

Adjusting the modeling assumptions to reflect RPS and RCP will create new graphs to supplement or replace all of the graphs on slides 39-50.

We can assume the slides as shown are appropriate for reflecting the performance of a 100% NG fired fleet of thermal plants in the portfolio margin.

The graphs can either be replaced or supplemented by similar graphs reflecting the less than 100% role for gas fired generation in meeting new load that must conform to RPS and RCP as it occurs from electrification of end uses.

For example in round numbers for the period covered by a 33% RPS policy (e.g. the near future), increased electric loads would result in roughly 2/3 as much annual pollution as shown in the 100% gas fired margin plots.

Hydro Modeling

As a long time hydropower modeler, I have a concern about the dispatch algorithm that results in slide 46. The issue shows up in all 5 days of the 33% RPS graph at far right.

It's easiest to first see in the sunny mid-day hours of spring days 70 and 71, but it happens in all 5 days.
Flexible hydro power is being ramped up in mid day, resulting in the curtailment of other plants.

Better modeling would have flexible hydro power being ramped up in other hours to displace more higher value load following resources and minimized in the low value curtailment hours.
Or alternatively some percentage of hydropower can be deferred more than a day if river release conditions are met.
Or the "Baseload" generation could be slightly reduced for a several day stretch and hydro reshaped into it leaving space above to reduce curtailments.

Upstream Emissions on Gas and Electric

I think it also makes sense to explore upstream emissions of both NG and electric systems and include fugitive emissions from incomplete combustion processes wherever they occur.

For both systems this would include: drilling, production, treatment and compression shrinkage consumption and fugitive emissions along the path until final partially complete combustion occurs for the molecules that successfully delivered.

I tend to believe there is about a 5% fugitive emission rate in the NG system and several percentage points of additional combusted upstream consumption associated with gas processing and repeated compression along pipelines (sometimes called shrinkage).

Possible Evolution of Thermal Services Companies
I hope gas utilities pivot themselves into being in the thermal services business and not just in the chemical delivery business. I think they would find a vibrant future in the expanded business model of providing thermal services. For example this could allow them to use their directional boring techniques to install thermal energy sharing plastic pipe water loops between exothermic customers (commercial areas) and endothermic customers (residential areas) and provide heat pumps to cool buildings and push the waste heat into the loop and other customers would use heat pumps to extract the heat from the loop. Perhaps they would operate more elaborate district heating and cooling systems like those becoming popular in Europe.

I would be happy to discuss these matters further and answer any questions about my comments.

Thank you for considering my comments and suggestions regarding your important analysis.

Sincerely,

Tom Kabat
Energy Consultant
tomgkabat@gmail.com