FROM: FTI Consulting, Inc. and Gas Supply Consulting

TO: California Public Utilities Commission

DATE: Tuesday, November 9, 2021

RE: Answers to questions not addressed during Workshop 3 and questions asked subsequent to Workshop 3

CPUC Staff:

Below are the answers to questions that were not addressed during Workshop 3 and questions asked subsequent to Workshop 3 during the comment period. The questions are organized by the portfolio themes presented during the workshop.

Portfolio 1a and 1b

1. Are there not benefits to narrowing basis spread between Border and CityGate? That would result in a gas cost (and electric cost) reduction.

   We modeled the change in gas price at SoCal and PG&E Citygates. GPCM is a monthly price model and its results suggested that on a monthly basis there was no change in prices at these two locations. We also mention, Portfolio 1a replacement supply is exposed to possibly higher gas costs during peak day conditions as discussed in the footnote on page 27 and 38 of the workshop presentation.

2. For your Note on Slide 27, isn't this true for other scenarios?

   This question refers to Portfolio 1a's possible need for firm transportation and possible exposure to peak day gas price conditions. The other portfolio solutions would not incur this same cost as Portfolio 1b (Wheeler Ridge expansion) is about increasing access to storage on the PG&E system and already includes firm transportation and storage costs. The remaining portfolio solutions s are about reducing gas consumption, and, as such, firm transportation and peak gas price exposure would not directly apply.

3. Did you incorporate the gas transmission expansions into the GPCM model and run it for 2027 and 2035? If yes, what impacts did it have on regional prices and flows? If not, why not?

   Yes, we incorporated the gas transmission expansions into the GPCM model and ran it for 2027 and 2035. GPCM showed no monthly market price impacts at SoCal and PG&E Citygates because these portfolios were essentially substituting for Aliso. See response to #1 in this section for additional info.

4. How did FTI determine these were the best locations for looped pipeline and that there is not an easier, more economical route?

   In each of the four expansion scenarios, we utilized our transient hydraulic model of the SoCalGas system to develop a potential expansion facility alternative that provides a lowest cost expansion while supporting deliverability requirements absent Aliso Canyon. This said, it is worth noting that there are many combinations of pipeline loop and compression facility expansions that could be utilized to support each proposed incremental capacity requirement on the SoCalGas system. As such, the projected facility expansions that we have identified may not exactly correspond to a facility expansion scenario determined by SoCalGas or another third party. However, we have worked to develop a "lowest cost" expansion scenario based upon our understanding of the cost of installation of pipeline loop and/or compressor horsepower.

5. How much increased capacity was needed at Quigley Station?

   The Quigley station was assumed to be expanded by 300 MMcf/d for each of the gas transmission portfolio solutions in our models. This provided sufficient capacity in each scenario.

6. How does a loss of withdrawal capacity at Playa Del Rey simulate the loss of a major transmission pipeline, particularly for an analysis that depends upon expanded pipeline receipt capacities and supplies?

   After establishing the average capacity outage assumption of 212 MMcf/d, which is the outage to be protected against, we recognized that this gas would need to be transported from the receipt points to markets (including the LA Basin). As such, reducing supplies available in the LA Basin (i.e., at Playa Del Rey) is representative of a loss of capacity on any segment of the pipeline system that transports to the LA Basin.

7. How did FTI increase the receipt capacity at North Needles by 50% without any incremental compression at North Needles, Kelso, or Newberry?

   The pipeline loop reduces the pressure drop across the pipeline system absent a need to increase compressor horsepower. The receipt pressure into the system is held constant in all cases. There was some excess (unutilized) compression capacity in the base model. The combination of: (a) reduced pressure losses with the pipeline loop; and (b) the use of the previously excess compression capacity in the shortfall models provided the capacity required to support the incremental receipts in the model.

8. On the hydraulics, have you double checked the values? San Diego linepack appears well below where it should be.

   Values were double-checked. There are no errors.

9. Coast and Valley zones look potentially switched.

   No, they are not switched.

10. Is the 395 MMcfd shortfall based on 85% utilization or on the Updated values of 95% you noted in slide 30?

    The shortfall is based on the same utilization percentages as in the Phase 2 modeling (85% in the Northern and Southern Zones and 100% in the Wheeler Ridge Zone). The expansion scenarios (Portfolios 1a and 1b) assume a 95% receipt point utilization at each of the Wheeler Ridge, Northern and Southern Zones. This said, as Otay Mesa is not always a liquid supply point location, receipts into the Southern Zone have been further limited based upon a maximum receipt quantity of 50 MMcfd at Otay Mesa.

11. The Commission has approved much higher per/mile costs for new pipeline infrastructure than FTI lists in its work papers for Portfolio 1A&B. Could you please explain why you use lower per mile pipeline costs instead of the higher per mile pipeline costs? For example, line 1600 rerouting has higher pipeline costs than FTI assumes.

    The line 1600 project is a 16" pipeline replacement project that is arranged as a series of numerous small distinct replacement projects. In contrast, the proposed Portfolio 1a and 1b expansion projects are long length, large diameter (36") pipeline projects. As such, we selected similar, long length, large diameter (36") projects as a basis to develop our benchmark costs supporting our expansion cost estimates.

12. GSC briefly mentioned that the analysis only uses 50 MMcfd at Otay Mesa. That is 12.5% of capacity. Can you go into more detail on why only 12.5% of capacity is available and what your source information is on that?

    As mentioned in the presentation (Slide 31), Otay Mesa is not heavily traded and is an illiquid supply source. To ensure that peak supplies are available, it was determined that reliance upon supplies at Otay Mesa at levels above 50 MMcfd was not reasonable.

13. SoCalGas is now entering the 5th peak demand season without returning L235 and L4000 to full operating capacity. Envoy states that those lines are still operating at 880 MMcfd below full capacity. Have you ever seen a pipeline rupture take that long to repair? If yes, please list 2 examples. If not, are you proposing a different owner and operator would be selected for the new gas infrastructure in Portfolio 1a?

    We have not researched and therefore have no opinion as to whether there have been any pipeline ruptures that have taken this long to repair. We are not proposing a different owner and operator for any selected new infrastructure.

14. Am I reading the working papers correctly? Portfolio 1A would be 3/4 of a billion dollars on new gas infrastructure before considering O&M, price overruns, and the 6.4% capital recovery factor?

    Yes, this is correct.

15. How was the price of gas impacted by closure of Aliso Canyon? Was there an increase in gas cost in Plexos when Aliso is closed?

We didn't model a scenario where just Aliso is closed without any portfolio solution to replace it, so we cannot answer these questions.

16. What type of gas and GHG price assumption is applied in the study? What TPP scenario was used? The Base case which is a 46 MMT GHG target or the 38 MMT sensitivity? The IRP is proposing to adopt a 38 MMT case, how will the results be impacted if the 38 MMT case is used?

    We assumed pipeline quality natural gas. We used the IEPR carbon prices in our PLEXOS modeling. The TPP scenario used was the 46 MMT GHG target. We can't comment on how the results would be impacted by using the 38 MMT case without modeling it.

17. Regarding assumption of 95% receipt point utilization during peak days, are you assuming that firm gas supplies and firm upstream capacity is used? If yes, where are those firm supply costs? If not, what is the basis to assume that the gas will be available at the border on a peak day. Didn't you say in the last workshop that the CA southern receipts were cut roughly in half during the Texas cold weather issue?

    Estimated firm upstream capacity costs have been incorporated into the Portfolio 1a cost benefit analysis based on prevailing market rates.

18. California energy policy targets carbon neutrality by 2045. That means portfolio 1A&B (gas infrastructure) will quickly become stranded assets and portfolio 3 (new renewable generators) will be required anyway. Can you talk about how the portfolios account for that?

    The cost-benefit analysis accounts for all costs and benefits specific to a portfolio regardless of whether costs become stranded or not going forward.

19. Why was the Gregg Engineering hydraulic modeling software chosen? Gregg Engineering software is for modeling point to point pipelines not gas system networks. Why was it chosen for use in this project over DNV Synergee, which is the industry leader for simulating gas system networks, and the system SoCalGas uses to model its gas system?

    The premise of this question is incorrect. Gregg Engineering NextGen software is specifically designed to create hydraulic simulation models of natural gas pipeline networks. Gregg Engineering software supports steady state and transient analysis of pipeline networks and is used by pipeline operators and engineers in the design and operational analysis of distribution, transmission, and gathering systems worldwide.

    The election to utilize the Gregg Engineering software was discussed in detail in the Phase 3 Workshop #1 held on November 17, 2020.

20. Was the SoCalGas system network modeled for the network congestion specifically near where the Aliso Canyon storage field is connected to the gas system network?

    As was discussed in detail in Phase 3 Workshop #1, the SoCalGas system network modeled by FTI/GSC was created by converting the CPUC Phase 2 Sim 01 Hydraulic model from the DNV Synergee modeling platform to Gregg Engineering's NextGen software. As part of this conversion, all facilities, and operating parameters in the Synergee model (including those near the Aliso Canyon storage field) were converted and included in the Gregg Model simulations.

21. Please provide the justification, including specific gas system modeling results, for the gas system transmission looping improvements that are being recommended when Aliso Canyon is on the opposite side of the LA Basin.

    Please see the answer to Question #4 in this section. Also, the hydraulic modeling results indicated, for both expansion portfolio solutions, successful model runs with line pack recovering over a 24 hour period, minimum pressures maintained and MAOP's not exceeded systemwide, including within the LA Basin.

22. Was SoCalGas' actual gas system network models used in the hydraulic modeling for this project? If not, why not and how can FTI assure that the modeling for this project reflects actual conditions.

    As noted above, a version of SoCalGas gas system network model was provided to FTI/GSC by the CPUC (CPUC Synergee Gas SIM 01 Hydraulic Model).

    As discussed in Phase 3 Workshop #1, initial steps in FTI/GSC's development of the hydraulic model were to:

    - Convert the model from Synergee to Gregg NextGen software,
    - Verify that the converted model facilities were consistent with the Synergee files;
    - Input receipt and delivery quantities consistent with a snapshot (steady state) version of CPUC's Phase 2 - SIM01 model
    - Verified that the delivery quantities and delivery pressures at all locations across the SoCalGas system were consistent with the results of the CPUC Phase 2 model.

    This process ensured consistency between the base model used by CPUC (which was sourced from SoCalGas) and the base Gregg Engineering NextGen model utilized by FTI/GSC to model the system.

    This model, demonstrated to provide consistent results with the SoCalGas Synergee model, was then utilized as a basis to develop the shortfall analysis and the gas transmission expansion scenario analyses.

23. Was a multi-day summer or winter weather event modeled for this project? If not, why not and what is the impact if such occurs which is likely especially in summer?

    As indicated in the line pack charts illustrated in the Appendix to the Phase 3 Workshop 3 presentation materials, the hydraulic simulations were run for a period of four days assuming that the peak day demand condition repeated each day for four days. As indicated in the charts, the models indicated that line pack recovered completely each day of the simulation.

Portfolio 2

1. Can you provide more details on the reverse auction concept for the non-core demand response? (slide 42)

Reverse auction here means that individual non-core, non-electric customers would be invited to participate in a process where they would be asked to provide the volume of demand reduction (in MMCFD) that they would be willing to offer and at what compensation (e.g., 10 MMCFD at $0.30/MMCFD, 20 MMCFD at $0.35/MMCFD) and so on. The provisions of the contract that would result from the process would be known to bidders (e.g., notice provisions, enforceability through direct load control).

2. For electric EE, did you factor in that about 30% of the goal is made up of Fuel Substitution (AKA Building Electrification)?

   Yes. The numbers were extracted from the Guidehouse results viewer and Fuel Substitution was filtered out.

3. Why would the reverse auction only include Demand Response? Why would you not also look at BE and EE?

   BE and EE would be part of a broader program being pursued for multiple reasons distinct from Aliso shutdown. For these programs, we estimate a level of procurement and associated cost and factor that into Cost-benefit.

4. Why does the cost-benefit analysis for BE/EE not also include the other avoided costs in the Standard Practice Manual?

   There would be an inconsistency between our study which uses $51/ton for social cost of carbon. In the case of BE, the net cost taken from the CEC report does not include a cost of carbon. Rather it uses the cost of the program to estimate the cost of carbon reduction.

5. Did the model for summer peak take into account the high efficiency of heat pumps which could result in lower summer peak?

   For modeling purposes, the efficiency of heat pumps is assumed to be a function of temperature.

6. What was the reasoning behind using American Gas Association assumptions on efficiencies of electric technologies for the purposes of this analysis?

   To provide context, we first relied upon the 2021 CEC Report for electrification load and gas demand impacts as follows:

   - The 2021 CEC Report provides a 2030 projection by scenario of how much gas use is converted to electricity, as well as how much electric energy use increases because of building electrification in California.
   - The estimates from the Moderate scenario are used directly to project the levels of electrification in FTI's work. For example, on page 43 of the workshop presentation, California-wide gas converted to electricity in 2030 under the Moderate scenario of 1580 MM Therms comes directly from the 2021 CEC Report.

- In subsequent steps, this level is adjusted to derive 2027 Southern California gas converted to electricity for the four applications of interest.
- The corresponding increase in electric energy is also from the 2021 CEC report and shown on page 44 of the workshop presentation.

The AGA information enters FTI's work solely for purposes of estimating an hourly load shape associated with the conversions as follows:

1. Hourly HDD and CDD observations are obtained from NOAA.
2. Temperature is reconstructed from the HDD and CDD data as follows:
    a. If CDD > 0, Temperature = 65° F + CDD
    b. If HDD > 0, Temperature = 65° F – HDD
    c. If CDD = 0 & HDD = 0, Temperature = 65° F
3. Revised HDDs and CDDs are calculated as follows, based on a 70° F inflection point, rather than a 65° F inflection point to reflect Southern California conditions
    a. If Temperature > 70° F, CDD = Temperature - 70° F
    b. If Temperature < 70° F, HDD = 70° F – Temperature
4. The hourly shape for cooling demand is constructed as follows:
    a. $\%\ \text{Cooling Demand in Hour X} = \frac{\text{CDD in Hour X}}{\text{Annual sum of CDD}}$
5. The hourly shape for heating demand is constructed as follows:
    a. $\text{Effective HDD in Hour X} = \text{HDD in Hour X} * \frac{1}{\text{Heat Pump Efficiency at Temperature}}$
        i. This step simply acknowledges that the efficiency of heat pumps varies with temperature. This temperature-dependent efficiency is the only place where AGA information enters the calculation and has no bearing on the level of electrification. It was used because it is a readily-available source showing the relationship of temperature to heat pump efficiency.
    b. $\%\ \text{Heating Demand in Hour X} = \frac{\text{Effective HDD in Hour X}}{\text{Annual sum of Effective HDD}}$
6. The hourly shape estimated in Step 5 is used to allocate the annual electric energy gained through conversion (separately for heating and cooling in MWh) from the 2021 CEC Report (as discussed) to derive an hourly electric load shape in MW.

7. How many days per year did you assume industrial gas demand reduction would be required to meet gas demand? Just the peak day or additional days? The reverse auction contract would specify that as "up to x days during the winter months."

    For modeling purposes, only the 1:10 peak day was considered. Program details related to the number of days, sequential or otherwise, on which Demand Response participants would be required to curtail usage would be established through a collaborative design process, subject to CPUC approval.

8. Are payments for Noncore demand response assumed to continue in perpetuity?

    The payment structure for Non-Core Demand Response would be established through a collaborative program design process, subject to CPUC approval.

9. How was the peak day identified in the demand response program and how was it communicated to the customers?

   In the demand response program referenced, as detailed in National Grid's (NY) 2020-2021 Expanded Gas Demand Response Implementation Plan, events were declared no less than 20 hours prior to the start of the first curtailment window if forecasted low temperatures at predetermined weather stations were 10 degrees or less. Events were communicated via customers' preferred method of communication (e-mail, text, etc.)

Portfolio 3

1. Slide 33 mentioned EG Profiles developed by FTI using PLEXOS model for years 2027 and 2035. How are those EG profiles developed? Is this electricity system study focus on the winter days? What type of electricity demand assumption is applied?

   The "EG profiles" on slide 33 refers to gas demanded from the electric generation sector on the 1 in 10 peak winter day in 2027 and 2035. This comes from our PLEXOS modeling in both years. The Workshop #1 presentation materials have more detail on how the load forecasts were constructed using materials from the IEPR.

2. On Slide 13 - why focus only on IOU obligations? Why not all LSEs?

   The IOUs correspond directly to balancing authorities that exist in our PLEXOS model, so we assumed the resources for those IOUs would be placed within the balancing authorities. All of the other LSEs are not modeled separately but as the Commissioner said, the requirements aren't really geographically dependent.

3. Shortfall Memo question: The difference in the shortfall between 2027 and 2035 equals 72 MMcfd or 301 MW of capacity. So Does FTI assume that the Commission will only order 301 MW of new renewable NQC between 2027 and 2035?

   There's no source for 301 MW of capacity stated in this question. It's not a value that was calculated by FTI/GSC. We are unable to answer the question as a result.

4. For instance, if Portfolio 3 is required anyway, should the price of the generators be listed as an additional cost for closing Aliso Canyon?

   There is no existing requirement that Portfolio 3 be required.

5. Shortfall Memo: In 2027 and 2035 the shortfall only appears for 3 hours (9pm to midnight), correct?

These hours are the ones focused on for sizing the electric solution portfolios, as lower gas generation due to units being unable to secure fuel was unable to be replaced with imported power.

Yes, in these hours, certain gas generators are unavailable and the shortfall cannot be addressed with imported power.

6. I had a question about the wind and solar generation profiles for portfolio 3. Could you expand on what system assumption were used to calculate the capacity factor profiles for both wind and solar? Was it 1-axis tracker system, what about the Inverter-loading ratio?

   We relied on Energy Exemplar, the licensor of PLEXOS, to provide these shapes. We have inquired with Energy Exemplar and are awaiting their response.

Portfolio 4

1. For a Transmission Expansion, wouldn't you need to have firm rights to electricity generated? We model all transmission as having a wheeling charge, so this is incorporated in the marginal price of wholesale prices modeled. The modeling is based on dispatching the available energy on the winter peak day. In counting benefits, we attribute RA benefits to transmission. We use current levels of RA prices for imports as reported by CPUC. This will reflect at least in part the "hair cut" for RA coming from imports.

2. Shouldn't the average cost of transmission consider mileage as well as cost per kW? Longer lines cost more than shorter ones . . .

   As noted during the presentation, the transmission analysis is not built around a specific project because even if such a project were identified it would be a multi-year process to obtain an estimate of its impact on the CAISO interface limit. We rely on a generic $/kW across several projects in the West.

3. In 2017 LADWP and CAISO said the minimum local generation for Southern California equaled 38 MMcfd to 293 MMcfd. Did LADWP and CAISO miscalculate the capacity of their transmission systems?

   We don't have any reason to believe LADWP and CAISO miscalculated the capacity of their minimum local generation.

4. To get a resource adequacy benefit from the transmission scenario, wouldn't you have to pay capacity payments to generators outside of California? Those costs don't appear to be in the estimated cost of the scenario?

The transmission scenario addresses whether the shortfall could be met if certain transmission limits such as the CAISO interface limit were eased through transmission projects. Wheeling charges for the transmission system have already been included in the PLEXOS model and thus are reflected in the market prices used to calculate portfolios' cost-benefit.

Other

1. Do the costs and benefits in the economic analyses include all the impacts that customers would potentially see? Would an NPV analysis yield similar results?

   Total costs were evaluated, with all costs converted into 2019 dollars. The rate impact to customers would be determined by the relevant CPUC regulations related to utility cost recovery for each project.

2. Has there been any discussion with Refineries about their ability to participate in Demand Response? Feedback I've received from my Refinery customers is that they would be extremely resistant to curtailing gas usage.

   FTI/GSC have not engaged in any direct contact with individual customers, however SoCalGas indicated in docket 18-11-005 (Nov 2018) that they were pursuing a demand response Load Reduction Pilot ("LRP") targeted at large customers and that SoCalGas account executives would be conducting outreach and educating large gas users about LRP. FTI/GSC have been unable to locate any public documents related to the results of this promised outreach.

3. For the electric energy efficiency portfolio, you list incremental costs of $417 million in 2027 and $575 million in 2035. Due to large estimated benefits listed in the Guidehouse study, you decided not to include and costs or benefits from these programs in your cost benefit analysis, but did include energy and peak demand reductions. You state that the large benefits in the Guidehouse study are due to high avoided GHG savings. Why not include the costs and use FTI's avoided GHG cost to estimate benefit.

   That would be inconsistent with our assumed social cost of carbon.

4. Modifying my last question to say, "What happens if you allow for a nat gas burn limit for SoCal but don't do transmission additions for Winter Peak demand over 3 days? Are there various burn limits you could set if you combine this solution with other solutions in Portfolio 5?"

   We have not modeled a burn limit with limited transmission additions.

5. CAISO 2022 Local Capacity study shows a need in the LA Basin for 6646 MW, and only 1020 MW of that can be replaced one-for-one with 4-hour storage due to charging limitations. How would we get the remainder of the 3176 MW needed in LA Basin to replace gas? Can't site wind or geothermal in basin . . . .

We don't understand the question.

6. You mentioned earlier that you did not do a LOLE reliability analysis because the system is assumed to be reliable portfolio. Once you consider the increase in electric load due to building electrification and other decarbonization efforts like Electric Vehicle charging, should a LOLE analysis be conducted to understand if the generation portfolio can meet the requirements of this new higher electric load shape in 2027 and 2035?

   LOLE reliability analysis focus on the peak hour, which occurs in the summer for California. This study is focused on the peak 1:10 winter day.

7. Does focus on the "most constrained hours" result in certain short duration resources to appear more attractive? Would it help understand reliability impacts if future analysis also looked at multi-day events? For example, cold weather conditions that last several days, instead of one day or hours during a day.

   The focus on the most constrained hours was only for sizing the generation portfolio and was not a determinant of the resource mix. Our focus was only on the 1:10 peak winter day, not a multi-day event.

8. It would be helpful to have more detail and detailed workpapers on the cost benefit analysis. The level of detail is also different across portfolios. For some of the portfolios, the workpapers do have total costs, which can be 10-14x the "Levelized Annual Cost." It would be helpful to see the total costs for Portfolio 3.

   CPUC provided the cost-benefit analysis workpaper. Detailed cost/benefit analysis calculations will be provided in the final report.

9. The July 9 Assigned Commissioner's Ruling said there would be opening and reply comments after this workshop #3 (in addition to a workshop #4), but the ALJ Ruling setting the workshop limits party input to just opening comments and does not allow for reply comments. Further, instead of the two weeks provided to develop comments after workshops #1 and #2, we only have one week for the workshop #3 comments. Can the deadline for the comments be extended to two weeks (so Nov. 17 not Nov. 10) and can we reply?

   Comments on the workshop are due on November 10, as noted in CPUC's September 30 ruling, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M411/K231/411231581.PDF, and restated on November 8,
   https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M421/K082/421082398.PDF.

10. Is there going to be opportunity for written comments?

    See above.

11. Has FTI run additional sensitivities to assess the impact on the shortfall of lower RPU for the Northern and Southern Zones?

No.

12. So, will you need to increase the amount of gas in Aliso? I was told that it was necessary for winter demands but also told that if you vote for it tomorrow, timing wise, the gas would not be ready for be injected for the winter demand.

The Phase 3 study is examining options for closure of Aliso Canyon in 2027 or 2035.

13. Does winter EG gas demand peak on the same days as core winter gas demand, or do other factors beyond temperature drive EG winter gas demand

We have assumed that EG and core winter gas peak on the same day for this study.

14. FTI said the LADWP generators were definitely subject to supply constraints, and would be subject to gas demand response. I had asked if they could identify which generators. Fleshing out the question: did they model specific generators having to shut off, or did they just look at a total volumetric gas demand that would have to go unserved?

We modeled specific generators being unable to receive gas in descending order of unit heat rate. Consistent with Phase 2 modeling, we will not be providing an unredacted list of curtailed units.

15. What granularity did FTI use: hourly? We're concerned over the increasing need for sub-hourly modelling due to renewable generation volatility. It's possible that hourly modelling may not accurately capture the magnitude and frequency of gas swings on our grid.

All PLEXOS modeling was done at the hourly level.