Target 3 Draft Report Public Version – Review of SSC Comments

Note: Obvious typos (missing spaces, misspellings, etc.) are not included in this list. Additional changes may be made to commented text changes to resolve grammar, acronyms, stylization, etc. In addition to changes resulting from SSC comments, other clarifying changes have been added to the report where appropriate. Page numbers reference the comment documents from the specific commenter that are posted to the EIPC website.

#	Commenter	Comment	LAI Response
1	Con Edison	Figure ES-1, which shows the amount of generation affected by each contingency is interesting, but the contingencies are not specifically identified. Is that information available somewhere?	The contingencies are specifically identified in the CEII version of the report. Individuals who wish to have access to that information will need to request it from one of the six regional EIPC Planning Authorities that are participating in the study – ISO New England, IESO, New York ISO, PJM, MISO, or TVA. Requests should follow the procedure posted on the EIPC website at http://www.eipconline.com/EIPC_Documents.html. Such requests will need to include an explanation of why it is appropriate for the individual to receive the information. If an individual does not reside within the boundaries of one of the six participating Planning Authorities, they should choose the participating Planning Authority that is geographically closest to their location.
2	Con Edison	The baseline model for NYISO shows a significant amount of "undeliverable energy", even during summer months. Why are the results so different from the Target 2 conclusions that there are constraints during winter, but not summer months?	The model used in Target 2 did not take hydraulic factors into consideration. The summer undeliverable energy is due to generators that cannot maintain delivery pressures above 485 psig in the baseline. The basis for the 485 psig threshold is discussed in Section 2.1.2 of the report, which is included in the public version. The Executive Summary has being revised to clarify the baseline results, and the CEII version of Section 3 includes more detail regarding specific affected plants.
3	Con Edison	It is not clear from the discussion what the "undeliverable energy" quantities represent. Are they the amounts of gas needed to maintain transmission security (assuming no back-up fuel) or are they the difference between the ideal dispatch and the actual dispatch that is feasible to meet transmission security?	The undeliverable energy reflects the amount of generation that is scheduled on gas in the electric simulation model results to which gas cannot be delivered due to pressure or flow restrictions. The existence of scheduled energy with undeliverable gas does not mean that electric supply is in jeopardy - affected dual-fuel-capable generators could switch to alternate fuels, and other electric re-dispatch options are available. The study is not an electric reliability analysis; the electric simulation model was not iterated to test alternate dispatch strategies.
4	Con Edison	The Executive Summary mentions that the Lower Hudson Valley and downstate New York could be affected by contingencies. Was the Capital Region not so affected or was it not mentioned for other reasons?	In NYISO, the bullets specifically referencing contingencies in LHV and downstate NY reflect areas where LDC analysis was conducted. LDC analysis was not conducted in the Capital District because the generators affected by the relevant contingencies are directly connected to the interstate pipeline(s).

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5	Con Edison	As a general matter, we're disappointed with the "extrinsic mitigation" sections of the report, which seem to get into general policy recommendations that don't seem supported by much analysis. The discussion of the PPAs' planned market changes, in particular, seems off-topic.	The discussion of mitigation measures is required by the Statement of Work. The extrinsic measures are not meant to "endorse" any particular market design. Stakeholders understand PPA sponsored works that are still in progress.
6	Con Edison	Page iii: "Nearly all gas-fired generators served by an LDC in PJM and NYISO lack firm transportation rights, either by choice or due to lack of availability of such a tariffed service, depending on the LDC." Comment: We evaluate the cost of firm service from time to time when generators request it. We've found that the cost, not the existence of a tariff service, is the major impediment. Additionally, like transmission expansions on the NYS transmission system, the cost of gas system expansions for a large, new customers sizeable and vary substantially, depending on the location of the customer and the level of service desired; thus, an "off-the-shelf service" for generators is not possible.	No changes made. A generator's choice not to contract for firm service could be due to cost or other considerations, but is addressed in the existing cited language. Con Edison's experience regarding tariff services may not be applicable to all LDCs in PJM and NYISO. More information on available LDC tariff services is provided in the Target 1 report.
7	Con Edison	Page iii: "For the postulated electric-side contingencies, on the Winter Peak Day in 2018 a significant amount of gas for scheduled gas-fired energy cannot be delivered in ISO-NE, NYISO, and PJM." Comment" This bullet should acknowledge NYS's large fleet of dual fuel generation, which is sustained largely because of LDC tariff requirements.	The Executive Summary bullets have been revised. Language regarding the dual-fuel capability of the NYISO generation fleet is incorporated in what is now the fourth bullet in the Key Results section.
8	Con Edison	Page iv: "Insofar as affected generation is not tantamount to unserved electric energy, it is important to note that additional non-gas fueled resources or other gas generation in non-constrained locations may be dispatched or ramped up to replace the energy from the affected gas-fired units." Comment: This is a helpful sentence that should also be included in the Target 2 report.	Similar language is already present in the T2 report on page 11: "The identification of affected generation in a given location does not indicate that electric system reliability in that location is in jeopardy. The reported affected generation represents a seasonal peak hour condition under a fixed dispatch pattern; as such, iterative redispatching has not been performed to investigate the availability of gas-fired generation at other locations, or other mitigation measures ascribable to non-gas fired generation resources." The referenced language will also be included in the Phase 2 Executive Summary or Condensed Report.
9	Con Edison	Page vi: "During the winter, the less resilient and less adaptable segments of the gas pipeline network, which are less able to sustain gas-fired generation, are found in the MAAC area of PJM – both SWMAAC and EMAAC, the LHV and Capital District zones in NYISO, and ISO-NE." Comment: Was Capital District evaluated in this phase of the study?	Yes, the Capital District was evaluated in Target 3, although LDC analysis was limited to the Lower Hudson Valley, New York City and Long Island.
10	Con Edison	Page ix, Figure ES-1: It isn't clear to us what period these GWH deliveries would be lost for – 24 hours? Might be better to show MW of capacity lost during worst interval.	The axis label in Figures ES-1 and ES-2 has been revised to read "Undeliverable Energy in First 24 Hours (GWh)."

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11	Con Edison	Page 3: "The WinFlow steady-state model incorporates the average gas demand level for RCI customers and gas-fired generators over a 24-hour period." Comment: Does this mean that the estimates of GWh of undeliverable energy are for a 24 hour period?	Yes, the estimates of GWh of undeliverable energy are for a 24-hour period. WinTran, the transient model used to determine undeliverable energy, was run for 24 hours before and 24 hours after the start of each contingency event. This is the basis for the reporting period, not the 24-hour steady-state representation of the gas day in WinFlow.
12	Con Edison	Pages 3-4: "As discussed in Section 2.1.2, after the steady-state hydraulic models for pipeline systems of interest were tested and calibrated, they were converted into WinTran transient models, wherein hourly profiles of system operating conditions and demand profiles are simulated throughout the gas day differentiated between RCI and generation customers." Comment: What proportion participated?	All pipelines, RCI customers and generators in the modeled regions are included in the analysis. Pipeline information was obtained from FERC. RCI customer information was developed in Target 2, and generator information was provided by the PPAs, with demand forecasts generated in Target 2.
13	Con Edison	On page 6: "For purposes of this study, the peak day represents coincident peak RCI gas demand and peak electric generation gas demand." Comment: What does this sentence mean? RCI and electric generation peak hour was assumed to be the same hour?	RCI and electric generation demands were assumed to peak on the same day, but the peak hour of the two sectors may differ. For clarity, the sentence has been revised to "For purposes of this study, the peak day represents coincident peak <u>day</u> RCI gas demand and peak <u>day</u> electric generation gas demand."
14	Con Edison	Page 7: "Technical commentary received from those pipeline companies who elected to comment was limited to the accuracy of the technical input parameters affecting deliverability, including interconnect flows." Comment: What proportion provided input?	All pipelines operating in the modeled area – consisting of the Study Region except for MISO South – were provided with a copy of their steady-state pipeline model and given the opportunity to comment. Approximately half of the pipelines provided feedback.
15	Con Edison	Page 10: "The example in Table 2 illustrates how 660 MDth/d of forecast demand in RGDS winter 2018 was allocated *pro rata* to individual meters." Comment: Essentially prorates load increases among existing meters.	For clarity, the sentence has been revised to "The example in Table 2 illustrates ~~how~~ <u>that</u> 660 MDth/d of forecast demand in RGDS winter 2018 was allocated *pro rata* to individual meters <u>based on 2012 peak day meter demands</u>."
16	Con Edison	Page 10: "Demand associated with generators that are served by LDC systems with multiple pipeline connections was allocated to the LDC delivery meters based on the proximity of the generator to the relevant gate stations, existence of dedicated laterals, contracted volumes and other factors." Comment: How does this come out for NYC?	In Con Edison's service territory, generator demands in the interstate pipeline models were allocated to one or more of the Iroquois (Hunts Point), Transco (Manhattan, Central Manhattan) and Texas Eastern (Manhattan) gate stations based on the location of the generators. For purposes of the contingency analysis conducted by Con Edison, the LDC is assumed to have relied on additional internal information regarding the expected gate station receipt points associated with each generator's demands.

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17	Con Edison	Pages 12-13: "Absent specific information from generators regarding minimum pressure requirements and the availability of on-site compression, LAI incorporated a minimum pressure requirement of 485 psig as the cut off point to capture any impairment in operation. While most CT units can operate at reduced load at pressures significantly below the minimum pressure for full load operation, the 485 psig cutoff pressure, including a 25-50 psig allowance for metering and regulation losses, represents a reasonable pressure level for many CT technology types in the Study Region." Comment: As noted by email, Con Edison can sustain pressures to many of its generation customers at lower than 485 psi, because the newer ones have compressors and the older ones don't need the pressures. We don't know if this information would affect the analysis or not.	The contingency analysis of Con Edison's system was conducted by Con Edison, and therefore is assumed to reflect information known by the LDC regarding the minimum pressures associated with specific generators. Language reflecting this aspect of the LDC analysis has been added on page 13: "LAI evaluated local deliverability issues following postulated gas and electric side contingencies at the local level for many LDCs in PJM, NYISO and IESO. In PJM, those LDCs that conducted independent hydraulic analysis of their respective local distribution systems included BGE, Nicor, and Peoples. In NYISO, Con Edison and NGrid conducted independent hydraulic analysis. In IESO, TransCanada, Enbridge and Union Gas conducted independent analysis. The aforementioned LDCs utilized internal information about generator-specific minimum pressure requirements rather than the 485 psig minimum pressure cutoff level used elsewhere in the Study Region."
18	Con Edison	On page 14 LAI states "A conservative aspect of the post-contingency modeling approach is that hydroelectric resources, which are often relied upon to provide additional generation after a contingency, were not redispatched. That is because those resources were scheduled against load, which did not change in the contingency cases." Comment: Don't understand the second sentence. What is "scheduling against load"? Does that mean that the hydro resources were already maxed out pre-contingency or that they were just assumed to be on a fixed schedule? In New York, hydro resources are an important source of operating reserves.	For clarity, "due to a model limitation" has been added to the end of the first sentence. Instead of using available hydro resource operating reserves the model often increased imports. On the peak winter and summer days, hydro resources were modeled on a fixed schedule.
19	Con Edison	Page 36, Figure 21: How are the number of GWH determined? Is that the total for a 24-hour period following a contingency? The text could make that clearer. Also, it might be easier to understand the MW of capacity that are unavailable.	For clarity, the following sentence was added to the introductory paragraph of section 3: "The reported GWh of deliverable and undeliverable energy were calculated on the basis of each unit's full load heat rate and the amount of deliverable and undeliverable gas during the 24 hours following the start of the contingency." It would be difficult to also show the MW unavailable since that value varies over time based on unit dispatch.
20	Con Edison	Page 36, Table 10: It isn't clear to us why these results differ so much from the Target 2 estimates of unserved load, especially in summer. Can that be explained in simple terms?	For clarity, the following language was added to the introductory paragraph of section 3: "Baseline results for undeliverable energy differ from those of Target 2 because it used a different model, GPCM, that was not hydraulic, and therefore did not incorporate pressure considerations. Additionally, Target 2 reported constraints only during the seasonal peak hour, rather than the 24-hour reporting period used in Target 3."

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21	Con Edison	Pages 48-49: This section jumps back and forth between contractual and physical capabilities of the system in a way that is confusing. We suggest laying it out more simply: storage withdrawals (including LNG), increases in receipts, and line pack could potentially be used to sustain service to interruptible customers. However, pipelines may not be permitted to use those resources to sustain service to interruptible customers following a contingency.	Language has been revised in conjunction with other specific comments. See #37, 43 and 45.
22	Con Edison	Page 48: "However, most pipelines do not have storage withdrawal rights." Comment: The sentence is confusing. Does this refer to rights at third-party storage facilities?	Language revised in conjunction with INGAA comments: "However, most pipelines do not have storage withdrawal rights; usually, the rights are controlled by the storage customer, thus necessitating coordination with one or more storage entitlement holders."
23	Con Edison	Page 49: LAI states "However, following an extreme event, the availability of PAL in a constrained region may not help sustain continued service to gas-fired generators without potential impairment to firm entitlement holders." Comment: PAL service generally is an interruptible service. It is not clear to us how it would help address a contingency that affects a pipeline's ability to render interruptible services.	Language added before referenced sentence: "While PAL services may have a non-firm character of service, use of PAL service during the peak cooling season, in particular, may offer operators a dependable short-term solution to local area constraints." Footnote 75 revised to read: "During the heating season, l~~L~~imitations on the use of PAL to help sustain service to gas-fired generators following a contingency would be likely."
24	Con Edison	Page 49: "Satellite LNG tanks are used predominantly to ~~protect~~ serve RCI customers. They are likely not available to ~~slow rate of re-liquefaction coupled with truck transportation delivery constraints render this mitigation measure almost always infeasible for purposes of~~ sustain~~ing~~ gas-fired generation in downstate New York and in New England following a contingency."	Proposed language revised as follows: "Satellite LNG tanks are used predominantly to ~~serve~~ protect RCI customers. The~~y are likely not available to~~ slow rate of re-liquefaction coupled with truck transportation delivery constraints render this mitigation measure almost always infeasible for purposes of sustaining gas-fired generation in downstate New York and in New England following a contingency, particularly during the heating season, November through March."
25	Con Edison	Page 54: "From a policy perspective, the capacity market structural changes promulgated by ISO-NE and PJM have the potential to enhance gas deliverability to gas-fired generators throughout the year, including during the peak heating season, thereby increasing ISO-NE's and PJM's ability to mobilize gas-fired generators on short notice following an extreme event." Comment: It isn't clear how this recommendation is supported by the analysis in this report (or any analysis at all). We had hoped that this report would focus on providing factual information and leave the policy decisions to stakeholder processes.	The discussion of mitigation measures is required by the Statement of Work. The extrinsic measures are not meant to "endorse" any particular market design. Stakeholders understand PPA sponsored works that are still in progress.
26	Con Edison	Page 55: "Information sharing through Order 787 has the potential to allow both gas and electric system operators to better address contingency events, although issues with the voluntary nature of Order 787 were noted previously." Comment: Same comment as above.	See #25

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27	Con Edison	Page 55: "As discussed in the Target 4 report, establishment of market rules that provide generators with reasonable assurance of cost recovery for variable costs borne to test dual-fuel capability, including switching on-the-fly, would likely improve capacity performance during cold snaps or outage or supply contingencies." Comment: Why not mention that New York's large fleet of dual fuel generation is the result of LDC requirements that generators on their systems be dual fuel capable – specifically, the requirements are imposed by Con Edison, O&R, National Grid Long Island and Central Hudson?	Footnote added: "<u>In NYISO the large amount of dual-fuel generation is largely a consequence of LDC tariff requirements to preserve fuel assurance throughout the year.</u>" Language revised to reflect comment and the New York State Reliability Council's requirements that have a direct bearing on availability and use of oil to satisfy fuel assurance objectives across the New York Facilities System.
28	Con Edison	Page 56: "*A fifth extrinsic mitigation measure* relates to innovative services formulated by interstate pipelines that are designed to reduce scheduling risks posed by balancing charges and ratable take restrictions." Comment: We suggest deleting the discussion of pipeline services. Although the services may be useful, it isn't clear what problems they address or how they relate to the contingency analyses presented in this report. Also, there are plenty of other helpful pipeline/LDC services out there.	The inclusion of the discussion regarding pipeline innovations is consistent with the Statement of Work. It is clearly stated that these are only examples.
29	EISPC	Page iv, Study Approach: This may be too much information for the Executive Summary.	The information will be further distilled for inclusion in the Phase II Report Executive Summary and Condensed Report.
30	EISPC	Page v, Study Region Results: The body of the report does not include the sensitivity results. It goes from the Baseline Analysis to Contingency Mitigation without discussing the contingency results.	The contingency results are classified as CEII and therefore not included in the public version of the report. Instructions for requesting the CEII report are included in Comment #1 at the beginning of this document.
31	EISPC	Page 3, Footnote 3: "The deliverability assessments in IESO were conducted by the pipeline <u>(operator?)</u> and the LDCs with input from LAI."	Language revised to: "The deliverability assessments in IESO were conducted by ~~the pipeline and the LDCs~~ <u>TransCanada, Enbridge and Union</u> with input from LAI."
32	EISPC	Page 12: "Model solutions in WinTran require the incorporation of a pressure cutoff level below which the generation plant either cannot operate or cannot operate at full power output." Phrasing is awkward.	Language revised to: "Model solutions in WinTran require the incorporation of a pressure cutoff level below which the generation plant either cannot operate <u>at any output level</u> or cannot operate at full power output."
33	EISPC	Page 12: "Absent specific information from generators regarding minimum pressure requirements and the availability of on-site compression, LAI incorporated a minimum pressure requirement of 485 psig as the cut off point to capture any impairment in operation." For those of us that do not have a gas background, it would be helpful to define this abbreviation (and how is it different from plain old psi?). Also, it is not included in the list of abbreviations.	psig added to List of Abbreviations as "<u>pounds per square inch gauge (pressure relative to atmospheric pressure instead of relative to zero)</u>" and written out in text where it first appears.

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34	EISPC	On page 17, LAI states "For SCGT generators larger than 100 MW, LAI applied a technical fuel use profile, shown in Figure 7, that begins with a 3-minute purge (no fuel input), followed by 5-minute set points until full output at 28 minutes." Table 3 indicates that it takes 2 hours to full output but this says 28 minutes. Is one of them wrong or do they represent different things?	Table 3 and Figure 7 represent different things. Table 3 shows the commitment lead time to full output for large CTs, which is restricted to 2 hours because many of those units are CT components of combined cycle plants. The fuel input profile in Figure 7 is representative of simple cycle CTs.
35	EISPC	On page 56, LAI states "Another example of an innovative rate design is on the El Paso Natural Gas Pipeline Co. (El Paso), a Kinder Morgan company." A Kinder Morgan company seems out of place and unnecessary.	Multiple pipelines in the Study Region are also operated by Kinder Morgan, the existence of these services specifically on a Kinder Morgan-operated pipeline is therefore relevant.
36	NGSA	Pages 22 and 49: We believe that LNG import facilities should be modeled at nameplate or send-out capacity (in the same manner as with the pipelines) rather than with assumptions on market decisions that can and do change rapidly. One cannot disregard the potential send-out capacity (operational capacity) whether it is currently being utilized or not. As demonstrated by system performance this winter, the west to east constraint was mitigated with injections of LNG from the East. Given that LNG vaporization played a key role in meeting that peak demand this winter, it is at least as reasonable to expect more advanced contracting for LNG supply and utilization of the import terminals as it is to assume less or none in the 2018 and 2023 timeframes, and therefore, we believe it's capabilities should be modeled accordingly.	The decision to assume no regasification of LNG at the Repsol Canaport and Suez Distrigas import facilities, excluding send-out to New Mystic 8&9, was based on Target 2 study goals and information available to LAI and the PPAs in 1H-2014. Assessment of stakeholder contracting decisions to rely on LNG imports was not part of the Target 2 study design or research objectives. A footnote is included in Section 2.3 to reflect the change in operating regime of the Canaport and Distrigas LNG import terminals in 2014-15 relative to 2013-14 has been noted in a in Section 3.2. This change may or may not be indicative of market dynamics in 2018 and/or 2023. The impact of significant regasification at Canaport and Distrigas on the baseline results can be extrapolated from Sensitivity 16 of the Target 2 analysis.

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37	NGSA	Pages iv and 44-57: The model for this study fails to consider a pipeline's contractual obligations. The failure to take these important contractual relationships into account means that certain key aspects of the suggested mitigation measures are divorced from the reality of how a pipeline is contractually obligated to operate in an actual contingency event. Contractual commitments between a pipeline and a shipper, incorporating the pipeline tariffed rates and FERC-approved terms and conditions of service, are at the very core of the relationship between an interstate pipeline and its shippers. These contractual commitments are reflected in pipeline scheduling priorities even during force majeure events. Thus, it follows that, if generators require a high level of service in order to ensure they are not the first ones cut during emergency situations, the most critical mitigation measure they must pursue is to contract sufficiently from firm pipeline services. Perhaps the reference on page 53 of the draft to "hardening" the supply chain through electric market design is intended to reference suggestion does not stand out as one of the most critical actions that must be taken to ensure gas-fired generators can decrease their risks of not receiving delivered gas during contingencies.	We acknowledge the difference between the contractual obligations of the pipelines and the physical nature of this study. Pipeline scheduling practices and service priorities are discussed at length in the Target 1 report, sections 2.1.1 through 2.1.4. Pipeline services are discussed at length in the Target 1 report in sections 2.2.1 through 2.2.5. Additional information pertaining to contract rights for storage services and LDC services can also be found in the Target 1 report, sections 2.3 and 2.4, respectively. Also, specific curtailment priorities are discussed in the Target 3 report, section 4.1, including footnote 41. Language has been added to the first paragraph of the Executive Summary: "<u>Emphasis is placed on the physical capability of the consolidated network of pipeline and storage infrastructure across the Study Region to maintain service to RCI and gas-fired generation customers following a postulated gas-side contingency. Hence, a pipeline's contractual obligations are not explicitly recognized in the study approach. In accordance with their tariffs, pipelines would limit deliveries to non-firm customers following occurrence of a contingency event if necessary to preserve their ability to meet contractual firm customer demands. In order to determine the probable outer bound of how long service to an affected gas-fired generator could potentially be maintained following a specific contingency, a physical study was conducted, consistent with the Statement of Work, that did not differentiate between the character of service of RCI and generation customers. This approach examines (i) post-contingency pressures and flows in the event that system conditions do not require pipelines to limit generator deliveries in order to protect service to RCI customers; (ii) potential service duration to gas-fired generators in the event that they are relying on firm transportation either through third-party arrangements or an entitlement held in their own name; and (iii) how much time a PPA may have to redispatch other generators, both gas-fired and non-gas fired, to replace affected gas-fired generation. The results of the study support PPA awareness of the adaptability and resiliency of the consolidated network of pipeline infrastructure after a contingency.</u>"

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38	NGSA	The draft mentions several mitigation measures that will "help pipelines sustain service to gas-fired generators." For example, without more clarification, we are concerned that several of the suggested measures that are intended to help sustain service to generators (e.g. diversion of gas to higher priority generators, use of line-pack that supports pipeline operations and pipeline use of other shippers' committed "spare" no-notice or storage service) could be inadvertently constructed to mean that pipelines should provide a preference for one class of customers over another or could be used to support arguments for the creation of a preferred customer class for gas-fired generators. Based on contract based scheduling priorities, pipelines are not at liberty to provide preferential service to a particular customer class. Pipelines cannot simply "borrow" no-notice and storage rights that are committed to specific shippers and give them to others. Non-power customers represent nearly 70 percent of total gas consumption and the contractual rights of all customers need to recognize and protect. Therefore, we suggest that the mitigation section be clarified to stress that actions pipelines take during emergencies will be in an effort to help all of its customers by following the tariff-approved scheduling priorities that are based on contractual commitments.	The referenced mitigation measures relate to both physical and policy initiatives designed to promote improved gas/electric interdependencies. No recommendation is made to support the creation of a preferred customer class for gas-fired generators. Any tariff design changes would require FERC or state regulatory approval.

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39	NGSA	Another concern with the draft Report 3 (page 53) involves the suggestion that "PPAs may want to campaign for continued refinement" of pipeline scheduling and promote "broad-based, hourly scheduling protocols" through the gas and power industries have undertaken and completed a comprehensive and thorough evaluation of gas scheduling process improvements. Although still pending before FERC, the gas and power market participants were able to agree upon substantial improvements to the existing pipeline nomination schedule to assist power generation customers. Thus, suggesting additional changes in gas scheduling at this time is premature when the industry consensus has yet to be implemented nor has the regional power market made the conforming changes that will be required by FERC in its Section 206 proceedings. In fact, we believe that EIPC should incorporate conforming changes by regional power markets in response to FERC Section 206 actions as a mitigation measure in this report. Moreover, in November of last year, FERC initiated a fuel assurance initiative to examine efforts underway in each regional power market to ensure their respective energy and capacity markets provide the right price signals to incent generators to invest in reliable fuel commitments. Given the pending gas scheduling improvements and active FERC fuel assurance initiative, we fell that suggestions to "campaign" for additional gas scheduling changes over and above those agreed upon by industry representatives simply will not serve either industry well and, at best, would be premature.	Language revised to "PPAs may choose to pursue ~~want to campaign for~~ continued refinement"
40	INGAA	INGAA and its members recognize the need to simplify the underlying assumptions of a study in order to perform modeling efforts. Yet, INGAA is concerned that the study over-simplifies certain assumptions for purposes of the EIPC hydraulic modeling effort and, as a result, overstates or mischaracterizes the proposed mitigation measures. INGAA offers the following high-level observations and also provides comments and edits within the Target 3 draft report.	LAI appreciates the time and effort taken by INGAA to provide detailed comments on the Target 3 report. See responses to specific comments below.

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41	INGAA	INGAA notes that since a pipeline's contractual obligations are not recognized by the model, the report could leave PPAs and other readers with a false impression about what a pipeline could do in the event of an actual contingency. Pipelines, as open access providers, must act in a non-unduly discriminatory manner. Under the obligations created by the Federal Energy Regulatory Commission, a pipeline must serve customers based on the "firmness" of their transportation agreements. A pipeline cannot unduly discriminate based on end use to favor one customer or a class of customers (e.g., gas-fired generators) when other customers also may be affected by a contingency event and require transportation service. Further, per its tariff, a pipeline must provide service based on its scheduling priorities, which are based on contractual commitments. Therefore, a pipeline cannot take all actions to ensure transportation for an interruptible shipper when higher priority transportation shippers have requested transportation service. While the report briefly acknowledges that the modeling disregards a pipeline's contractual obligations, the report still could lead a PPA to assume that mitigation opportunities for gas-fired generators are greater than what would be available in an actual contingency.	See #37
42	INGAA	The report correctly assumes that pipelines work diligently to mitigate contingency events by using whatever tools are available to maintain reliability and mitigate the reduction of pipeline capacity, including using pipeline line pack, increased interconnect flows from neighboring pipelines, increasing spare compression, if available, and reversing flow across key pipeline segments. During peak winter and summer days, however, a pipeline's shippers, and interconnected pipelines' shippers, likely will need to use their full contractual entitlements. Therefore, it is highly unlikely that a pipeline would have available all of the mitigation measures suggested in the draft report.	Only those mitigation measures that are operationally feasible relative to the baseline infrastructure utilization in WinFlow/WinTran are represented in the model solutions on a Winter Peak Day and Summer Peak Day. On a Winter Peak Day, a pipeline's LDC shippers are typically using all or most of their full contractual entitlements, whereas on a Summer Peak Day, a pipeline's LDC shippers are typically only using a portion of their full contractual entitlements for their own use.

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43	INGAA	INGAA specifically is concerned that the draft report places too much emphasis on the ability to use pipeline line pack to mitigate electric or gas contingencies. Each pipeline has taken the hydraulics of line pack into account in designing its existing firm service obligations; there is little or no slack line pack capability. Line pack can be used by a pipeline to manage operational changes on its system and to provide shippers non-ratable flexibility when operations permit. Yet, a pipeline cannot exhaust line pack without affecting deliveries to other shippers and without causing operational harm to the pipeline system. Once exhausted, pipeline line pack cannot be replenished readily within the Gas Day and perhaps not even within the next several days. On a peak day, there is little or no excess line pack to provide shippers, including gas-fired generators, with flexibility beyond scheduled transportation. Therefore, ISOs/RTOs should not assume that a region can rely on line pack for electric reliability in the event of a contingency during a peak day (or any day). Line pack is not a substitute for an appropriate transportation contract and does not create incremental capacity.	The last bullet in the Key Results section of the Executive Summary has been revised to: "Line pack is a source of operational flexibility, not a source of incremental capacity. On a Peak Day, particularly a Winter Peak Day, pipelines' contractual obligations may result in little or no excess line pack being available to provide shippers, including gas-fired generators, with flexibility beyond scheduled transportation in some locations. Following a *force majeure* event, the affected pipeline(s) would curtail scheduled volumes as needed in order to protect deliveries to firm customers based on tariff priorities, and to preserve required line pack for purposes of system integrity. For purposes of this physical study baseline deliveries to RCI customers and gas-fired generators are maintained following a postulated gas-side contingency, resulting in some cases in drawdown of line pack downstream of the contingency location. Study results show that this ~~increased~~ use of line pack on a Winter Peak Day or Summer Peak Day in 2018 or 2023 can help sustain service to affected gas-fired generators located downstream of the contingency. This approach identifies the probable outer bound of how long service to an affected gas-fired generator could potentially be maintained following a specific contingency."
44	INGAA	INGAA wishes to clarify that there is never "spare" or unused no-notice capacity that can be allocated to another shipper, including a gas-fired generator, to mitigate a contingency event. A pipeline must stand ready to serve no-notice shippers that pay a premium for this highest-priority pipeline service, and accordingly, a pipeline reserves capacity specifically for these shippers. A pipeline will not know how much of the capacity reserved for no-notice service will be unused until the Gas Day is over. Therefore, INGAA requests that EIPC remove spare no-notice service as part of its modeling or mitigation analysis, if it was relied upon to elongate the time before a gas-fired generator would trip.	The use of "spare" no-notice services (NNS) was not an explicit part of any modeled solutions in WinTran. Consistent with feedback from INGAA's members, pipelines set aside the full amount capacity in order to meet the MDQ for those NNS customers if they all decided to max out their contract rights on a particular day (as opposed to only setting aside an assumed use on a particular day associated with the aggregate NNS load). The "reserved" NNS capacity is typically underutilized on an annual basis and sometimes even during cold snaps. As LAI understands it, "longs" and "shorts" can net out to less than 100% of NNS customers' requirements across the system before accounting for the diversity of NNS customers' usage profiles. Whether or not a pipeline would actually allocate spare NNS to another shipper, firm or non-firm alike, following a gas-side event is outside the scope of the analysis.

#	Commenter	Comment	LAI Response
45	INGAA	The draft report overstates the likelihood that a pipeline company would be able to use storage or LNG withdrawals to mitigate a contingency event during a peak day. In order for storage or LNG to contribute to mitigating a contingency event, the storage or LNG must be located downstream of the gas contingency and sufficiently proximate to the gas-fired generator so that the gas response time will mitigate the loss of gas from the pipeline. Further, the draft report should take into account the physical limitations of depleted reservoir storage in the Eastern Interconnection. If storage reserves are depleted due to earlier withdrawals, storage gas cannot be withdrawn or replenished as rapidly as if the storage reserves are not depleted. Finally, while the study recognizes that pipeline companies likely do not have withdrawal rights, the draft report also does not recognize that the gas within pipeline storage facilities is owned by the pipeline's shippers, not the pipeline. A pipeline cannot withdraw a shipper's gas without its authorization for another shipper's use. Therefore, INGAA requests that EIPC reflect in the report the unlikelihood of generators relying on pipelines for increased storage withdrawals to mitigate a contingency during a peak day.	INGAA's specific edits regarding storage-related mitigation measures have largely been accepted (see #75 and 76). In the model results, storage and LNG provide limited or no contingency mitigation because in most cases: (i) pipeline-connected LNG and storage facilities are not located downstream of the tested contingencies, (ii) peak day withdrawals from pipeline-connected storage and LNG facilities used as model inputs are taken from the relevant pipelines' Form 567 filings, without post-contingency increases, and (iii) behind-citygate LNG satellite storage facilities are not included in the consolidated pipeline models.
46	INGAA	In connection with using flow diversion as a mitigation tool, INGAA notes that some pipeline tariffs allow for gas flow diversions (diverting one shipper's flowing gas to another shipper's delivery point in the same geographic region), assuming the pipeline has the operational ability to do so. Yet, inherent in this tariff-based mitigation option is the original shipper's consent. As now drafted, the report could lead a PPA to assume that there are greater flow day mitigation opportunities for gas-fired generators than in fact are feasible.	Language added in the second-to-last paragraph of Section 4.2.1: "This flow diversion is only possible if the original shipper agrees and it is operationally feasible for the pipeline to divert gas to the alternate plant."

#	Commenter	Comment	LAI Response
47	INGAA	The report erroneously states that pipelines assess penalties to generators that attempt to nominate outside the standard NAESB cycles (assuming the pipeline does not have additional nomination opportunities in its tariff). If a control room operator provides a generator the opportunity to make an additional nomination, no penalties will accrue due to the ability to nominate. During critical operating conditions, however, penalties can arise if a shipper that nominates (or does not nominate) for additional pipeline transportation starts to consume gas without delivering the corresponding gas supply into the pipeline system, and continues to pull gas despite warnings from the pipeline that it is in violation of a critical day notice or Operational Flow Order. During an extreme event, a pipeline may notify shippers to remain in contractual daily balance during the critical period to maintain the operational integrity of the pipeline and to maintain its ability to serve primary firm transportation customers. On peak day conditions, if a generator or other shipper knowingly violates an OFO, it does so at the operational expense of the other pipeline shippers and knowing that it could harm the integrity of the pipeline system. An ISO/RTO should not reimburse generators for pipeline penalties incurred during an OFO, since this reimbursement incents generators to disregard pipeline notices and engage in operationally harmful behavior. INGAA requests that EIPC revise its final report accordingly.	While traditionally most ISO/RTO's will typically reimburse a generator for additional costs associated with following or trying to follow a dispatch order from their control room operator, nothing in this report speaks to the reimbursement of penalty costs. See #72 and #80 for specific language changes in the report.
48	INGAA	Page iii: "For the postulated electric-side contingencies, on the Winter Peak Day in 2018 a significant amount of gas for scheduled gas-fired energy cannot be delivered in ISO-NE, NYISO, and PJM." As drafted, the cause and effect relationship is unclear. Is the intent of the bullet to state that gas transportation or supply could not be delivered in the region on the peak day to support gas-fired generation scheduled for dispatch due to an electric contingency?	Bullet removed.

#	Commenter	Comment	LAI Response
49	INGAA	Page iii: "Study results show that ~~increased~~ use of line-pack on a Winter Peak Day or Summer Peak Day in 2018 or 2023 can help sustain service to affected gas-fired generators located downstream of the contingency. On peak day conditions, line pack is needed to filfill firm transportation obligations. It is unlikely that line pack flexibility would be available on a peak day to maintain non-firm service during the postedulated conditgency." Comment: INGAA does not agree with this conclusion. While use of line pack can help mitigate a contingency event, there is little or no extra line pack to sustain service to affected generators on peak days. On peak day conditions, line pack is used to maintain system operations and fulfill scheduled transportation obligations. EIPC should not assume that line pack can be used to sustain service to generators when it will be needed for all shippers.	See #43
50	INGAA	Page v: "Line pack is the volume of gas contained within a pipeline that allows gas in one area of the pipeline's system to be delivered simultaneously elsewhere on the system. ~~Packing the line increases the amount of gas in the system by adding gas or increasing pressure~~Adding new gas at a receipt point, without a corresponding delivery, increases pressure ("packs" the line), while removing gas at a delivery point, without a corresponding receipt, decreases pressure ("drafts"~~ing~~ the line ~~decreases the amount of gas or pressure in the pipeline segment~~). Pipelines use line pack to manage operational changes and to provide flexibility for situations such as unscheduled imbalances and non-ratable flows, but it is variable and limited. Line pack must be kept reasonably stable across the entire pipeline system to preserve delivery pressure and system capacity. Line pack is finite and cannot be overdrawn without operational consequences both for the pipeline and its shippers."	Proposed language revised to: "Line pack is the volume of gas contained within a pipeline that allows gas in one area of the pipeline's system to be delivered simultaneously elsewhere on the system. Adding new gas at a receipt point, without a corresponding delivery, increases pressure ("packs" the line), while removing gas at a delivery point, without a corresponding receipt, decreases pressure ("drafts" the line). Pipelines use line pack to manage operational changes and to provide flexibility for diverse operating conditions ~~situations such as unscheduled imbalances and non-ratable flows, but it is variable and limited~~. Line pack must be kept reasonably stable across the entire pipeline system to preserve delivery pressure and system capacity. Line pack is finite and cannot be overdrawn without operational consequences both for the pipeline and its shippers." Language was revised to be less specific about the potential uses of line pack.

#	Commenter	Comment	LAI Response
51	INGAA	On page v: "Hence, a pipeline's contractual obligations, and its scheduling and curtailment priorities based on the firmness of transportation service, are not explicitly modeled in the hydraulic analysis. Since these contractual obligations are not embedded in the model, the study's conclusions are likely to differ from how a pipeline would need to act, pursuant to its tariff, in an actual contingency event. The simulated pressure profiles of the gas pipeline system at the various gate stations reveal whether sufficient pressure and flow are available to sustain power plant operations for up to 24 hours following the start of the gas- or electric-side contingency."	Proposed language revised to: "Hence, a pipeline's contractual obligations, and its scheduling and curtailment priorities based on the firmness of transportation service, are not explicitly modeled in the hydraulic analysis. Since the~~se~~ multitude of the pipelines' contractual obligations are not embedded in the model, the study's conclusions may differ from how a pipeline would ~~need to~~ act, pursuant to its tariff, in an actual contingency event. The simulated pressure profiles of the gas pipeline system at the various gate stations reveal whether sufficient pressure and flow are available to sustain power plant operations for up to 24 hours following the start of the gas- or electric-side contingency." Language was revised to express the complexity of contractual obligations and to account for flexibility in pipeline operations.
52	INGAA	Page vi: "Following the postulated event, whether or not an interconnected pipeline c~~w~~ould permit ~~increased~~ interconnect flows, use of line-pack, or the reversal-of-flow across key pipeline segments is not known with certainty and would vary based on the unique circumstances of the contingency event and the pipelines' operating conditions . As noted earlier, under a real contingency event, firm service obligations would govern the pipeline's response. Other mitigation measures may also be available, but would require infrastructure investments that were not incorporated in the model solutions. Pipeline tariff provisions governing the nomination, ~~/~~ confirmation, and scheduling process ~~cycle~~ and daily imbalance resolution were not incorporated in the hydraulic models because this analysis was based only on the physical impacts on delivery in the event of a contingency, ~~rather than simply~~ and did not include an analysis of daily contractual obligations of shippers." Comment: As noted earlier, pipeline firm service obligations would govern the pipeline's response to the various contingencies.	Proposed language revised to: "Following the postulated event, whether or not an interconnected pipeline could permit increased interconnect flows, use of line-pack, or the reversal-of-flow across key pipeline segments is not known with certainty and would vary based on the unique circumstances of the contingency event and the pipelines' operating conditions. ~~As noted earlier,~~ Again, under a real contingency event, firm service obligations would govern the pipeline's response. Other mitigation measures may also be available, but would require infrastructure investments that were not incorporated in the model solutions. Pipeline tariff provisions governing the nomination, confirmation, and scheduling process and daily imbalance resolution were not incorporated in the hydraulic models because this analysis was based ~~only~~ on the physical impacts on delivery in the event of a contingency~~, and did not include an analysis of daily contractual obligations of shippers~~." Language revised based on consultant preferences and to avoid duplication of language in added in #37.
53	INGAA	Page vii: "Pipelines have an outstanding record of working together to maintain transportation system reliability. A pipeline may be able to lend capacity to an interconnected pipeline if it operationally can do so without reducing deliverability on its system and without compromising its operational integrity."	Proposed language revised to: "~~Pipelines have an outstanding record of working together to maintain transportation system reliability.~~ A pipeline may be able to lend capacity to an interconnected pipeline if it operationally can do so without reducing deliverability on its system and without compromising its operational integrity." Language revised to address stakeholder commentary.

#	Commenter	Comment	LAI Response
54	INGAA	Page vii: "Such pipeline protocols may include the use of line-pack, reversal-of-flow of downstream pipeline segments, more complete loading of pipeline interconnects, and enhanced use of spare or idled compression prior to the onset of the gas-side contingency. Still, the implementation of such pipeline protocols is highly dependent on pipeline flexibility, weather, and primary firm shipper needs at the time of the contingency on both the pipeline experiencing the contingency and interconnected pipelines. Communication initiatives among the PPAs, pipelines, and/or LDCs facilitate discussion about ~~have the potential to strengthen the usefulness of available~~ the mitigation measures that may be available to~~in~~ respon~~sde~~ to heightened gas/electric interdependencies across the Study Region in 2018 and 2023."	Proposed language revised to: "Such pipeline protocols may include the use of line-pack, reversal-of-flow of downstream pipeline segments, more complete loading of pipeline interconnects, and enhanced use of spare or idled compression prior to the onset of the gas-side contingency. ~~Still, t~~The implementation of such pipeline protocols is highly dependent on pipeline flexibility, weather, and primary firm shipper needs at the time of the contingency on both the pipeline experiencing the contingency and interconnected pipelines. Communication initiatives among the PPAs, pipelines, and/or LDCs ~~facilitate discussion about~~ have the potential to strengthen the usefulness of ~~the~~ available mitigation measures ~~that may be available to respond~~ in response to heightened gas/electric interdependencies across the Study Region in 2018 and 2023." Language revised based on consultant preference.
55	INGAA	Page 4, Footnote 5: "The pipelines were given the opportunity to review the modeling of their respective systems and many constructive comments were received and incorporated. Yet, not all pieplines use the WinFlow model and, therefore, not all pipelines were able to validate the data. The WinFlow model assumes ratable take consumption by RCI customers and does not reflect the variable demand afforded to customers with no-notice service or non-ratable transportation service contracts."	In cases where pipelines informed LAI that they did not use the WinFlow modeling platform, model infrastructure information was provided in an alternate format that the pipelines could access and import into their own modeling systems. The intra-day profile of RCI demand that was used in the transient models was provided in the Target 2 report for stakeholder review and comment.
56	INGAA	Suggested rewording on page 7: "The pipeline review process was conducted in Q4-2014 and January, 2015. Although requested to comment, not all pipeline companies provided technical comments. Pipelines did not review or comment on the modeling assumptions regarding the amount of line-pack within their systems."	The pipelines were not asked to comment on line pack assumptions and the report does not indicate that they were.

#	Commenter	Comment	LAI Response
57	INGAA	Page 44: "Most, but not necessarily all postulated gas-side contingencies may warrant a pipeline's declaration of force majeure, the invocation of which typically permits ~~transporters~~ <u>pipelines</u> to implement ~~broad and sweeping~~ operating protocols<u>, pursuant to their tariffs,</u> to maintain system integrity. Under FERC guidelines, a pipeline is permitted to exercise its reasonable judgment to determine whether or not the event warrants declaration of force majeure. There is a well-established FERC policy regarding the nature of events that qualify as a force majeure events ~~in response to pipeline safety and integrity management obligations under the Pipeline Safety and Hazardous Materials Safety Administration Act (PHMSA)~~." Comment: INGAA proposes that EIPC remove this clause since most force majeure events are "acts of God." This phrase implies that *force majeure* events typically are PHMSA-related events.	Proposed language revised to: "Most, but not necessarily all postulated gas-side contingencies may warrant a pipeline's declaration of force majeure, the invocation of which typically permits pipelines to implement <u>broad</u> operating protocols, pursuant to their tariffs, to maintain system integrity. Under FERC guidelines, a pipeline is permitted to exercise its reasonable judgment to determine whether or not the event warrants declaration of force majeure. There is a well-established FERC policy regarding the nature of events that qualify as force majeure events." Language revised to express the scope of operating measures included in pipeline tariffs.
58	INGAA	Page 44: "Since perturbations to a pipeline's steady state deliverability are buffered by line-pack, a time lag is typically observed between the occurrence of the event and the resulting changes in pressure and flow affecting continued operation of gas-fired generation." This paragraph is very unclear as to whether EIPC is speaking about pipeline curtailments of scheduled gas OR a pipeline not scheduling lower quality transportation services (e.g., interruptible or secondary firm) in response to constraints.	Language revised to: "Since perturbations to a pipeline's steady state deliverability are buffered by line-pack, a time lag is typically observed between the occurrence of the event and the resulting changes in pressure and flow ~~affecting continued operation~~ <u>resulting in curtailment</u> of <u>scheduled</u> gas-fired generation<u> following a gas-side contingency</u>." Language revised to clarify that post-contingency operations and curtailments are being discussed.
59	INGAA	Page 44: "<u>To respond to critical operating conditions, a pipeline may issue an OFO, which may require customers to remain in contractual balance and adhere to ratable takes. OFOs are issued in extreme operating conditions. Pipelines typically issue OFOs after issuing other levels of critical notices advising customers of operational conditions and the need for receipts to equal deliveries. In addition, a pipeline may issue a critical notice indicating that it may need to restrict service at certain points, and will not schedule gas, based on priority of service in order to preserve deliverability to primary firm customers.</u> ~~As a general rule, P~~pipelines <u>may need to</u> ~~will~~ limit all transactions in the affected area to shipments to primary firm transportation entitlement holders only. Depending on the severity of the event, non-firm shippers directly connected to the pipeline downstream of the event may be notified ~~to get off-line at once~~<u>that effective immediately the pipeline cannot offer service to shippers that do not hold primary firm capacity.</u> Under extreme events, <u>a pipeline may need to curtail scheduled volumes, as discussed above. D</u>~~d~~eliveries to firm customers may be curtailed as well, but such extreme events would typically warrant declaration of a force majeure event."	Change accepted, with the third and fourth sentences moved to a footnote because they provide supporting information about OFO usage

#	Commenter	Comment	LAI Response
60	INGAA	Page 44: "In reviewing the array of operator actions in response to gas side contingency events, there are two general sets of operator actions: first, intrinsic mitigation measures, that is, changes to physical flows on a short duration basis designed to maintain scheduled flow to all or the majority of firm customers, and, subordinate to firm customers' requirements, whatever non-firm customers' scheduled flow can be accommodated in accord with the pipeline's scheduling ~~curtailment~~ protocols; and, second, extrinsic mitigation measures, that is, pipeline outreach efforts that are engineered on an ad hoc basis to limit adverse impacts to firm and non-firm customers in accord with the pipeline's curtailment protocols." Comments: A pipeline may need to curtail scheduled volumes, as discussed above. This paragraph is very unclear as to whether EIPC is speaking about pipeline curtailments of scheduled gas OR a pipeline not scheduling lower quality transportation services (e.g., interruptible or secondary firm) in response to constraints. Is EIPC speaking about scheduling priorities/limitations OR curtailment?	Change accepted, language additionally revised to add "following a gas-side contingency" to the end of the quoted text to differentiate between scheduling and curtailment effects
61	INGAA	Page 44, Footnote 45: "[45] ~~Pipeline obligations for public safety and integrity management are defined in the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 issued by PHMSA of the U.S. Department of Transportation.~~ FERC has since provided clarification on the nature of force majeure v. non-force majeure events."	Change accepted
62	INGAA	Page 45: "Transient model solutions reflect the consolidated network of pipelines and storage infrastructure across the Study Region. Therefore, this model assumes ~~gas-on-gas interdependencies underlying~~ ideal operating conditions and physical flow capability of the ~~network of~~ interconnected pipeline network to allow ~~for the complement of~~ physical intrinsic mitigation measures to be implemented to mitigate the impact on potentially affected generation. For example, the portfolio of solution responses may include ~~more complete~~ use of line-pack and spare compressor horsepower, among other things. In an actual contingency, however, the ability of an interconnected pipeline to provide aid would be highly dependent on pipeline flexibility, weather, and primary firm shipper needs at the time the aid is contemplated." Comment: Particularly in post-contingency operations, there is little or no extra line pack available to sustain deliveries for shippers that have not subscribed to service and timely tendered gas supply.	Proposed language revised to: "Transient model solutions reflect the consolidated network of pipelines and storage infrastructure across the Study Region. Therefore, this model assumes ~~ideal~~ operating conditions and physical flow capability ~~of~~ reflecting that all equipment is in service and available on the interconnected pipeline network to allow physical intrinsic mitigation measures to be implemented to mitigate the impact on potentially affected generation. For example, the portfolio of solution responses may include use of line-pack and spare compressor horsepower, among other things. ~~In an actual contingency, however, the ability of an interconnected pipeline to provide aid would be highly dependent on pipeline flexibility, weather, and primary firm shipper needs at the time the aid is contemplated.~~" Language revised to clarify the assumed baseline operating conditions and to remove language that is not necessary.

#	Commenter	Comment	LAI Response
63	INGAA	Page 46: "Since interconnected pipelines lending operational assistance first must assure that such assistance will not adversely affect deliverability to their own customers, such assistance may not be available, particularly under peak day conditions."	Change accepted
64	INGAA	Page 46: "~~However, in LAI's experience, exact operator actions are neither spelled out in FERC approved tariffs nor set forth in a preset "rule-book" governing operator assistance. Although the pipelines'~~ The terms and conditions regarding scheduling and curtailment priorities under constrained or severe operating conditions are ~~transparent~~ outlined in pipeline tariffs. Pipelines issue different levels of critical day notices (including a, ~~the pipeline operator response(s) when~~ force majeure notice, which is the most restrictive notice)~~event~~ on pipeline EBBs as soon as practicable following an event. ISOs/RTOs can sign up to receive all pipeline critical day notices directly from the pipeline as soon as the notice is posted. Pipelines react quickly to address a contingency event ~~s are declared are not transparent. Actions are implemented on an episodic basis and quickly~~ through both formal and informal relationships with interconnected pipelines, shippers, point operators and producers ~~operational handshakes~~ via telephone, e-mail and other pipeline electronic communication protocols . Pipeline control room operators also regularly communicate with RTOs/ISOs during both peak and non-peak periods. ~~, but generally not relayed to RTOs/ISOs.~~ Depending on the cirumstances, o~~O~~perators may also be able to reverse the directional flow downstream of the postulated event. Each of these operational responses to a severe gas side contingency is incorporated in the reoptimization of gas flows in the minutes and hours following an event. Hence, the portfolio of intrinsic mitigation measures that allow pipeline operators may use to ~~reasonably~~ minimize disruptive impacts following the event have already been incorporated in the results of the Target 3 transient analysis." Comments: INGAA is unclear whether EIPC is referencing scheduling or curtailment. Pipelines do not curtail unless they cannot deliver already scheduled and flowing volumes. A pipeline may not schedule IT or secondary firm transportation but that is not curtailment. EIPC's comment that these post-contingency pipeline actions are not transparent infers some concern with the lack of transparency in the process. The gas industry works exceedingly well to cooperate as best it can post-contingency. Pipelines continually update their operating status during and after a contingency event.	Proposed language revised to: "However, in LAI's experience, exact operator actions are neither spelled out in FERC approved tariffs nor set forth in a preset "rule-book" governing operator assistance. The terms and conditions regarding scheduling and curtailment priorities under constrained or severe operating conditions are outlined in pipeline tariffs. Pipelines issue different levels of critical day notices (including a *force majeure* notice, which is the most restrictive notice) on pipeline EBBs as soon as practicable following an event. ISOs/RTOs can sign up to receive all pipeline critical day notices directly from the pipeline as soon as the notice is posted. Pipelines ~~react quickly to~~ typically address ~~a~~ contingency events through both formal and informal actions ~~relationships with interconnected pipelines, shippers, point operators and producers~~. Actions are implemented on an episodic basis and quickly through operational handshakes via telephone, e-mail and other pipeline electronic communication protocols. ~~Pipeline control room operators also regularly communicate with RTOs/ISOs during both peak and non-peak periods.~~ Depending on the circumstances, operators may also be able to reverse the directional flow downstream of the postulated event. Each of these operational responses to a severe gas side contingency is incorporated in the reoptimization of gas flows in the minutes and hours following an event. Hence, the portfolio of intrinsic mitigation measures that ~~allow~~ pipeline operators may use to minimize disruptive impacts following the event have already been incorporated in the results of the Target 3 transient analysis, although the unique operating characteristics that differ by pipeline would allow operators to undertake additional situation-specific responses." Language revised to reflect that specific operator actions are not included in the tariffs, only service priorities; consultant language preferences; PPA experience; and variance between pipelines.

#	Commenter	Comment	LAI Response
65	INGAA	Page 46, Footnote 47: “During the peak heating season or during cold snaps in shoulder months, replenishment of line-pack ~~may~~ will not be achievable within the current gas day. Under certain circumstances, a pipeline may not be able to restore line-pack to the target operational level for several days. Replenishment of line pack is very dependent on location, availability of supply, operating conditions and the nature of the postulated incident. Regardless, a pipeline cannot exhaust line-pack and continue to maintain system pressures.”	Proposed language revised to: “During the peak heating season or during cold snaps in shoulder months, replenishment of line-pack may ~~will~~ not be achievable within the current gas day. Under certain circumstances, a pipeline may not be able to restore line-pack to the target operational level for several days. Replenishment of line pack is dependent on location, availability of supply, operating conditions and the nature of the postulated event. ~~Regardless, a pipeline cannot exhaust line-pack and continue to maintain system pressures.~~” Language revised to remove declarative statement about future operations and statement with technical details, line pack is explained earlier in the report
66	INGAA	Page 47: “In this Final Rule, FERC refers to pipelines and public utilities that operate gas or electric transmission facilities as “transmission operators.” The Final Rule is designed to support the reliability and integrity of natural gas and electric transmission service by permitting transmission operators to share information that the operators deem necessary.”	Changes accepted
67	INGAA	Page 47-48: “~~However, c~~Compliance with the Final Rule is voluntary~~, which impacts the extent of any consistency between the level and type of information sharing by different pipelines. The voluntary nature of Order 787 potentially gives rise to an inconsistency in information sharing.~~. In the Final Rule, the Commission “intentionally permit[ed] the communication of a broad range of non-public, operational information to provide flexibility to individual transmission operators, who have the most insight and knowledge of their systems, to share that information which they deem necessary to promote reliable service on their system,” adding that it “is not practicable to develop a specific and exhaustive list defining the permissible communications.” Comment: INGAA does not agree with the negative inference that the information sharing between pipelines and ISOs/RTOs may be inconsistent. The FERC rule envisioned that different operators would want different information. There is no support that the voluntary nature of the information sharing is impeding information sharing.	No negative implication is intended or seems reasonably inferred from the existing wording.
68	INGAA	Page 47, Footnote 52: “However, there is no equivalent communications order for communications between the PPAs and non-jurisdictional LDCs. ~~may be less transparent.~~ The quality of service to a generator behind the citygate is generally governed by a negotiated agreement or tariff.”	Changes accepted
69	INGAA	Page 48, new footnote: “Order No. 787 at P 41.”	See #67

#	Commenter	Comment	LAI Response
70	INGAA	Page 48: "~~In some instances, the pipelines are aware, or have the potential to be aware, of the location and oil switching capability of gas-fired generators with either firm or non-firm transportation rights on their respective system.~~" Comment: INGAA suggests deleting this sentence since it is irrelevant whether the pipeline knows or has the potential to be aware whether generators are dual fuel. A pipeline cannot act to deliver gas until a generator nominates and the pipeline schedules the transportation after determining that the pipeline had capacity, the generator had associated supply and a transportation contract to support its nomination.	Change accepted
71	INGAA	Page 48: "Working in close consultation with their regional generators, the PPAs' electric control room operators may inform the pipeline of which generation unit(s) are currently most important (*i.e.*, must-run) for electric system reliability following a contingency event in an attempt to determine if the pipeline operators could implement best efforts mitigation measures that are simultaneously protective of RCI customers as well as the gas-fired generation units needed most for electric reliability." Comment: A pipeline must award capacity based on the contractual firmness of its shippers' contracts. If there is no capacity on the pipeline, a pipeline cannot transport gas, even for must run units, if other shippers with higher priority contracts want the capacity.	Language revised to add "<u>, subject to a pipeline's contractual obligations</u>" at the end of the quoted sentence

#	Commenter	Comment	LAI Response
72	INGAA	Page 48, Footnote 55: "~~Control room authorization for a generator to obtain natural gas outside the NAESB approved nomination / confirmation cycle may trigger penalties or other costs that the ISO/RTO Market Monitor may need to review for purposes of determining the reasonableness of full compensation.~~" Comment: INGAA proposes deleting fn 55. This footnote is incorrect. Pipelines do not penalize shippers for additional nominations outside of the NAESB process during an emergency if the control room operator has authorized the nomination. If the statement regarding other costs refers to unauthorized gas takes during an OFO, INGAA notes that pipeline tariffs permit a pipeline to assess a shipper or OBA party a penalty for remaining out of balance on the system, if the imbalance is causing or has the potential to cause operational harm to the pipeline. Most pipelines, under non-critical operating conditions, allow shippers flexibility to get back into balance within a certain period without assessing a penalty. While imbalance penalties assessed during such normal operating conditions are small, the financial penalties assessed when OFOs are in effect much greater because they are intended to deter shipper misconduct that could harm a pipeline's operational integrity and threaten the ability to meet its firm service obligations. The OFO may require customers to remain in contractual balance and adhere to ratable takes. OFOs are issued in extreme operating conditions. Pipelines typically issue OFOs after issuing other levels of critical notices advising customers of operational conditions and the need for receipts to equal deliveries. If a pipeline assesses a penalty to an offending shipper or point operator, FERC policy requires the pipeline to distribute the revenue from the penalty to non-offending shippers. The pipeline remains revenue neutral.	Proposed language revised to: "Control room authorization for a generator to obtain natural gas outside the NAESB approved nomination / confirmation cycle may trigger costs that the ISO/RTO may review for reasonableness. INGAA notes that pipeline tariffs permit a pipeline to assess a shipper or OBA party a penalty for remaining out of balance on the system, if the imbalance is causing or has the potential to cause operational harm to the pipeline. Most pipelines, under non-critical operating conditions, allow shippers flexibility to get back into balance within a certain period without assessing a penalty. While imbalance penalties assessed during such normal operating conditions may be relatively small, the financial penalties assessed when OFOs are in effect much greater because they are intended to deter shipper misconduct that could harm a pipeline's operational integrity. The OFO typically requires customers to remain in contractual balance, *i.e.*, take ratably. Pipelines typically issue OFOs after issuing other levels of critical notices advising customers of restrictive operational conditions that necessitate receipts to equal deliveries. If a pipeline assesses a penalty to an offending shipper or point operator, FERC policy requires the pipeline to distribute all of the revenue from the penalty to non-offending shippers." See #47
73	INGAA	Page 48: "As discussed in the aforementioned section pertaining to intrinsic actions, following a severe gas-side contingency, a pipeline operator would take steps immediately or almost immediately to fully utilize available pipeline interconnect capacity to bolster both pressure and flow into the constrained region. Pipelines cooperate on a best-efforts basis during contingencies to meet service obligations. If time allows following those scheduling changes, and depending on the severity of the event, a pipeline operator may reach out to other pipeline operators to take additional steps to manage load by "backing off" the scheduled volumes at gate stations and meters across the neighboring pipeline's system. However, this coordinated multiple operator response is contingent on shippers' ~~pipelines'~~ willingness to ~~cooperate with each~~ ~~other~~reduce their scheduled volumes."	Changes accepted

#	Commenter	Comment	LAI Response
74	INGAA	Page 49: "~~These extrinsic mitigation measures have the potential to trigger penalties for unauthorized gas use that exceeds a pipeline's approved tolerance level, daily imbalance charges, and other costs borne by a shipper to reconcile intra-day gas flow with scheduled nominations.~~" Comment: Unclear. Is this referring to penalties issued by a pipeline or an LDC? See concerns above about statements regarding pipeline penalties. INGAA suggests deleting this sentence since it is irrelevant to physical pipeline capabilities.	Proposed language revised to: "These extrinsic mitigation measures have the potential to trigger penalties for unauthorized gas use that exceeds a pipeline's approved tolerance level, daily imbalance charges, and other costs borne by a shipper to reconcile intra-day gas flow with scheduled nominations. Certain of these costs pertain to a shipper's obligation to conform to the pipeline's FERC approved tariff, which may cause the shipper to incur significant additional costs to remain in balance within the gas day." Language revised to clarify reference to pipeline operations.
75	INGAA	Page 49: "However, most pipelines do not have storage withdrawal rights; the rights are controlled by the storage shipper. For pipelines that do not have storage withdrawal rights, supplementing pressure and flow by scheduling storage withdrawals would require those pipelines to obtain storage withdrawal rights from other market participants." Comment: The draft report does not recognize that the gas within pipeline storage facilities is owned by the pipeline shippers, not the pipeline, and that a pipeline cannot withdraw a shipper's gas without its authorization for another shipper's use. Therefore, INGAA requests that EIPC reflect in the report the unlikelihood of generators relying on pipelines for increased storage withdrawals to mitigate a contingency during a peak day.	Proposed language revised to: "However, most pipelines do not have storage withdrawal rights; usually, the rights are controlled by the storage ~~shipper~~ customer, thus necessitating coordination with one or more storage entitlement holders. For pipelines that do not have storage withdrawal rights, supplementing pressure and flow by scheduling storage withdrawals would require those pipelines to obtain storage withdrawal rights from other market participants or, alternatively, for one or more storage entitlement holders to schedule storage withdrawals to bolster deliverability following an event." See #45. Language revised to further clarify coordination of storage utilization
76	INGAA	Page 49, Footnote 59: "On a Winter Peak Day, there may not be additional storage withdrawal capability to use to help restore pipeline integrity following the event. Storage entitlements generally are very location specific and rely not only on the storage facility capabilities, but also on the pipeline's transmission capability, which is designed and constructed to move gas from storage to a particular location. Storage withdrawls and LNG capacity may not be as easily transferred to critical locations as assumed in the study. In order for storage or LNG to help mitigate a contingency event, the storage or LNG must be located downstream of the gas contingency and sufficiently proximate to the gas-fired generator so that the gas response time will mitigate the loss of gas from the pipeline. In addition, once storage reservoirs are depleted, they may not be able to be refilled during winter."	Proposed language revised to: "On a Winter Peak Day, there may not be additional storage withdrawal capability to use to help restore pipeline integrity following the event. Storage entitlements generally are very location specific and rely not only on the storage facility capabilities, but also on the pipeline's transmission capability, which is designed and constructed to move gas from storage to a particular location. ~~Storage withdrawals and LNG capacity may not be as easily transferred to critical locations as assumed in the study.~~ In order for storage or LNG to help mitigate a contingency event, the storage or LNG must be located downstream of the gas contingency and sufficiently proximate to the gas-fired generator so that the gas response time will mitigate the loss of gas from the pipeline. ~~In addition, once storage reservoirs are depleted, they may not be able to be refilled during winter.~~" See #45. Language revised to remove reference to assumption that is not made in the study results. Storage depletion is not relevant on the January peak day examined in the study.

#	Commenter	Comment	LAI Response
77	INGAA	Page 50: "~~Third, a gas control operator may be able to bolster deliverability by leveraging the use of no-notice service. Many pipelines across the Study Region provide no-notice service. To the extent there is "spare" no-notice service built into the hourly profiles and levels of gas throughput on any given day, operators may be able to utilize such volumes in order to sustain service to gas-fired generators.~~" Comment: INGAA suggests deleting these sentences since they factually are inaccurate. Inherently, there is not "spare" no-notice service. Under a no-notice contract,a pipeline must reserve and stand ready to transport the shipper's requested capacity. Therefore, a pipeline cannot determine until the end of the gas day whether there was any unused capacity. In addition, no-notice service is often provided via a combination of line pack and transmission facilities designed and reserved to meet the customer's peak needs and storage. If LAI is adding no-notice service on top of linepack and storage as part of its modeling and mitigation measures, it may be double counting pressure and capacity availability in its transient model.	Proposed language revised to: "Third, a gas control operator may have flexibility to be able to bolster deliverability by leveraging, to a limited extent, the use of no-notice service. Many pipelines across the Study Region provide no-notice service. To the extent there is "spare" no-notice service built into the hourly profiles and levels of gas throughput on any given day, operators may be able to utilize such volumes in order to sustain service to gas-fired generators, particularly during the peak cooling season when LDC loads are typically a fraction of the LDC loads during the peak heating season." See #44
78	INGAA	Page 50, Footnote 63: "~~Within the limits of a customer's no-notice entitlements, injections and withdrawals by a customer do not need to adhere to nominated and scheduled quantities. Whether or not a pipeline may draw on underutilized no-notice service to mitigate an adverse event depends on the pipeline, the location, the temperature condition, and the distribution of "shorts" and "longs" across the system.~~"	Proposed language revised to: "Whether or not a pipeline may draw on underutilized no-notice service to mitigate an adverse event depends on the pipeline, the location, the temperature condition, and the distribution of "shorts" and "longs" across the system." See #44.

#	Commenter	Comment	LAI Response
79	INGAA	Page 51: "~~When ISO/RTO control room operators give dispatch instructions to gas units to supplant lost generation from a large power plant or by wire, gas-fired generators often scramble to obtain sufficient fuel to accommodate the unscheduled level and hourly profile of gas requirements following the event. Gas use to accommodate intra-day electric scheduling following the event has the potential to trigger ratable-take penalty charges, daily imbalance charges, and/or unauthorized use charges, thereby requiring the ISO/RTO market monitor to review the reasonableness of full or partial cost reimbursement. Additional costs for intra-day gas procured after the occurrence of an electric-side contingency event may include a substantial cost premium against the daily mid-point index price, penalties levied by the pipeline, LDC, or marketer, and daily imbalance charges. Also, generators covered under an Asset Management Agreement (AMA) may be responsible for financial charges payable to the supplier associated with a de facto no-notice service. ISO/RTO market rules that provide the ability to change bids in the real time market (RTM) is an intrinsic mitigation measure that may help address these incremental fuel costs.~~" Comments: INGAA proposes deleting this paragraph. The report is supposed to be about the physical capability of the system in a contingency event. This shifts the discussion to talking about penalties, which is irrelevant to the discussion about physical pipeline capabilities. Regardless, the paragraph factually is inaccurate. There is only a higher cost of intra-day supply related to pipeline transportation if the shipper violates an OFO, consumes too much of its gas non-ratably in violation of the tariff and the pipeline cannot accommodate such flexibillity. It is not fair to argue that intra-day gas is more expensive due to the penalties incurred by a generator violating a critical notice or inappropriate level of contract.	Language revised to: "When ISO/RTO control room operators give dispatch instructions to gas units to supplant lost generation from a large power plant or by wire, gas-fired generators often scramble to obtain sufficient fuel to accommodate the unscheduled level and hourly profile of gas requirements following the event. There is a higher cost of intra-day supply related to pipeline transportation if the shipper violates an OFO, consumes too much of its gas non-ratably in violation of the tariff and the pipeline cannot accommodate such flexibility. Gas use to accommodate intra-day electric scheduling following the event has the potential to trigger ratable-take penalty charges, daily imbalance charges, and/or unauthorized use charges, thereby requiring the ISO/RTO to review the reasonableness of full or partial cost reimbursement. Additional costs for intra-day gas procured after the occurrence of an electric-side contingency event may include a substantial cost premium against the daily mid-point index price, penalties levied by the pipeline, LDC, or marketer, and daily imbalance charges. Also, generators covered under an Asset Management Agreement (AMA) may be responsible for financial charges payable to the supplier associated with a de facto no-notice service. ISO/RTO market rules that provide the ability to change bids in the real time market (RTM) is an intrinsic mitigation measure that may help address these incremental fuel costs." Language revised to reflect potential causes of higher intra-day costs. Discussion of penalties is not relevant to Statement of Work objectives.

#	Commenter	Comment	LAI Response
80	INGAA	Page 51, Footnote 64: "~~Traditionally, most ISO/RTO Market Monitoring Units will reimburse a generator for additional costs associated with following or trying to follow a post-contingency dispatch order from the ISO/RTO Control Room operator.~~" Comment: INGAA proposes deleting footnote 64. See previous INGAA edits about pipeline penalties. INGAA does not support cost recovery for pipeline penalties incurred by a generator during a contingency event. As stated above, pipeline tariffs permit a pipeline to assess a shipper or OBA party a penalty for remaining out of balance on the system, if the imbalance is causing or has the potential to cause operational harm to the pipeline. If a pipeline assesses a penalty to an offending shipper or point operator, FERC policy requires the pipeline to distribute the revenue from the penalty to non-offending shippers. The pipeline remains revenue neutral. ISOs/RTOs should not authorize generators to obtain unauthorized gas from a pipeline or remain out of balance when a pipeline issues an OFO or critical day notice in anticipation of the ISO/RTO compensating the generator for any penalties incurred. Establishing electric market mechanisms to ensure a generator's cost recovery of these deterrents would be counterproductive.	Language revised to read "Traditionally, most ISO/RTOs will typically reimburse a generator for additional costs associated with following or trying to follow a dispatch order from their Control Room operator. Nothing in this report speaks to the reimbursement of penalty costs." See #47
81	INGAA	Page 51: "The flow day diversion ~~Doing so~~ would require communication between the generator and the pipeline company based on information as to system conditions from the RTO/ISO control room and would need to be authorized under the applicable pipeline tariffs or contractual arrangements."	Changes accepted
82	INGAA	Page 51: "~~Since the transaction happens in the RTM, when the gas day is nearing the end or has very limited liquidity to accommodate additional hourly nominations, market participants may incur additional transaction costs and/or penalties.~~ Rather , electric market participants can adopt "mutual aid" contract provisions among themselves, which may include requirements for generators to release and redirect supply to others. EIPC should include this as a mitigation measure." Comment: INGAA suggest deleting this sentence. Again, it is irrelevant. Penalties do not reflect physical capability, but the economics of a generator trying to come on to the pipeline late in the day without commendurate supply.	The original text is in accord with the PPAs' experience when market conditions tighten in the intra-day market. For more information about penalties see Section 2.2.1 of the Target 1 report. Suggested substitute language raises potential legal issues and has not been explored.

#	Commenter	Comment	LAI Response
83	INGAA	Page 52: "In any event, the pipeline authority to take these additional steps to ensure electric grid reliability would need <u>authorization</u> ~~to be reviewed transparently with~~<u>from</u> the applicable federal or, in the case of LDCs, state regulatory bodies." Comment: Unclear. If this is suggesting that a pipeline would be asked to depart from its tariff, the pipeline would need authorization from FERC, and make the waiver available to all similarly situated shippers.	Proposed language revised to: "In any event, ~~the~~ <u>a</u> pipeline<u>'s or LDC's ability</u> ~~authority~~ to take ~~these~~ additional steps to ensure electric grid reliability would need ~~authorization from~~ <u>to be reviewed transparently with, and authorized by,</u> the applicable federal or, in the case of LDCs, state regulatory bodies." Language revised to reflect the required authorization.
84	INGAA	Page 52: "~~The nature and extent of operational information readily available to an ISO/RTO on pipelines' EBBs varies from pipeline to pipeline~~. <u>Pipelines must ahere to NAESB standards regarding pipeline operational and capacity posting information on their EBBs. Some pipelines exceed the NAESB standards and provide additional information.</u>"	Language revised to: "<u>The nature and extent of operational information readily available to an ISO/RTO on pipelines' EBBs varies from pipeline to pipeline.</u> Pipelines must adhere to NAESB standards regarding pipeline operational and capacity posting information on their EBBs. Some pipelines exceed the NAESB standards and provide additional information." Language revised to reflect the variation in the level of detail and nature of the information posted on various pipeline EBBs in addition to the minimum required by NAESB.
85	INGAA	Page 52: "~~Pipeline operators are available 24/7 and may therefore be able to effectuate increased gas flow and pressure to start-up and sustain gas-fired generator performance, provided this information is available and communicated to ISOs/RTOs.~~ Similar to the operator actions following gas-side contingencies, system responses can include the ~~increased~~ use of line-pack for one or more generators, increased horsepower at strategically located stations, point operator rescheduling of natural gas through interconnects, reversal-of-flow along key route segments to enable gas-fired generation, and deliveries via displacement with other gas-fired generators or LDCs. Under certain circumstances, LDCs may be ~~able~~ <u>willing</u> to reduce receipts at specific gate stations while increasing receipts at others in order to facilitate delivery to designated gas-fired generator plant gates located near them." Comment: INGAA opposes any suggestion that, with communication alone, a pipeline could allow a generator to stay on the system or come on to the system without requisite gas supply. A pipeline is bound by its tariff, and goes not own the gas. A generator requesting to come on to the system without supply could adversely affect other shippers.	Language revised to: "<u>Pipeline operators are available 24/7 and may therefore be able to effectuate increased gas flow and pressure to start-up and sustain gas-fired generator performance, provided this information is available and communicated to ISOs/RTOs.</u> Similar to the operator actions following gas-side contingencies, system responses can include the use of line-pack for one or more generators, increased horsepower at strategically located stations, point operator rescheduling of natural gas through interconnects, reversal-of-flow along key route segments to enable gas-fired generation, and deliveries via displacement with other gas-fired generators or LDCs. Under certain circumstances, LDCs may be willing to reduce receipts at specific gate stations while increasing receipts at others in order to facilitate delivery to designated gas-fired generator plant gates located near them." Language revised to reflect control room availability consistent with the Target 1 report
86	INGAA	Page 52: "<u>This flow diversion only is possible if the original shipper agrees and it is operationally feasible for the pipeline to divert gas to the alternate plant.</u>"	Change accepted
87	INGAA	Page 53, Figure 28: The Intra-day 2 schedule currently is posted at 9 pm CCT, not 8 pm CCT.	Change accepted

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88	INGAA	Page 53, Footnote 65: "On the same day, FERC issued an order initiating an investigation of the ISO and RTO scheduling practices. Specfically, the Commission established proceedings pursuant to section 206 of the Federal Power Act (FPA) to ensure that each ISO's and RTO's scheduling, particularly its day-ahead scheduling practices, correlate with any revisions to the natural gas scheduling practices ultimately adopted by the Commission in Docket No. RM14-2-000."	Change accepted
89	INGAA	Page 54: • "Timely nominations ~~begin~~ would be due at 1:00 PM, with scheduled quantities posted at ~~and conclude at~~ 5:00 PM the day prior to gas flow; • Evening nominations would be due at 6:00 PM, with scheduled quantities posted ~~conclude~~ at 9:00 PM on the day prior to gas flow; • Intra-Day 1 nominations ~~now~~ would be due ~~conclude~~ at 10:00 ~~PM~~AM, with scheduled quantities ~~effective~~ posted at ~~2~~1:00 PM of the current gas day; • Intra-Day 2 nominations ~~begin~~ would be due at 2:30 PM, ~~and conclude at 5:30 PM~~ with scheduled quantities posted effective at ~~6:00~~ 5:30 PM of the current gas day • New Intra-Day 3 cycle is introduced. Nominations would be due~~begin~~ at 7:00 PM, with ~~and conclude at 10:00 PM with~~ scheduled quantities posted ~~also effective~~ at 10:00 PM;"	Changes accepted
90	INGAA	Page 54: "Implementation of hourly scheduling procedures would likely strengthen a gas-fired generator's ability to obtain natural gas in the intra-day market, ~~reduce penalty exposure~~ while supporting the PPAs' ability to call on gas-fired generation in strategic locations following an electric-side contingency, or to mitigate other abnormal system conditions. While hourly nominations provide greater opportunities for shippers to schedule gas intra-day, hourly nominations do not create additional capacity on a capacity constrained pipeline."	Proposed language revised to: "Implementation of hourly scheduling procedures would likely strengthen a gas-fired generator's ability to obtain natural gas in the intra-day market, while supporting the PPAs' ability to call on gas-fired generation in strategic locations following an electric-side contingency, or to mitigate other abnormal system conditions. While hourly nominations provide greater opportunities for shippers to schedule gas intra-day, hourly nominations do not create additional capacity on a capacity constrained pipeline, but may allow more efficient use of existing capacity." Revised language reflects the potential benefits of hourly scheduling
91	INGAA	Page 56: "Information sharing through Order 787 has the potential to allow both gas and electric system operators to better address contingency events~~, although issues with the voluntary nature of Order 787 were noted previously~~." Comment: INGAA suggests deleting this phrase. There is no indication that the voluntary nature of sharing non-public information between pipelines and electric transmission operators has impeded communications during a contingency event or impeded the ablity to address a contingency event.	See #67

#	Commenter	Comment	LAI Response
92	INGAA	Page 57: “For any service, including these enhanced pipeline services, a shipper must sign a long-term firm transportation contract in order for the pipeline to have sufficient capacity to support such service and, if necessary, build incremental infrastructure to support the service. Pipelines do not make these enhanced or specialized services available, or build the infrastructure necessary to support such services, on speculation that at some point in the indefinite future a shipper may need the service during a contingency event.”	Proposed language revised to: “For ~~any service, including these~~ enhanced pipeline services, a shipper ~~must sign~~ would likely be required to enter into a ~~long-term~~ firm transportation contract in order for the pipeline to have sufficient capacity to support such service and, if necessary, build incremental infrastructure to support the service. ~~Pipelines do not make these enhanced or specialized services available, or build the infrastructure necessary to support such services, on speculation that at some point in the indefinite future a shipper may need the service during a contingency event.~~” Language revised to reflect uncertainty about the required contracts, and contract terms, associated with services which have not yet been proposed. Language additionally revised to address stakeholder commentary.