April 24, 2013

To: **FERC Staff and Commissioners For April 25 Technical Conference**

Re: **Conservation Law Foundation/Skipping Stone Solutions**

Introduction:

On March 21, CLF provided to the New England Gas/Electric Coordination Working Group and ISO-New England a set of potential solutions prepared with its consultant Skipping Stone, LLC. This document provides additional details on some of the near term and longer term solutions set forth in the March 21 submittal.

In January of this year, Skipping Stone distributed a White Paper which outlines a series of Gas and Electric Market restructuring and synchronization proposals (available at www.skippingstone.com). Full implementation of the solutions and proposals in the White Paper would likely require several years. There are, however, ongoing reliability and economic issues which are immediate in several regional markets; primary among them is New England. Working with the Conservation Law Foundation (CLF), Skipping Stone is focusing the proposals in our White Paper to resolve and help alleviate the supply and basis problems experienced in New England in winter 2012/13.

The White Paper presents refinements for a synchronized and mutually complimentary future market design. There are a number of adjustments and market tools that can be introduced, in short order, into the markets – as currently structured - which will contribute to reliability and more efficient market operations. These solutions can markedly diminish the extent of and excessive cost of the much cited "basis problem" by enhancing opportunities to utilize available capacity for electric generation.

Problem:

The "basis problem" has three inter-related but nonetheless distinct components. One is "illiquidity", another is "coordination" and the third is insufficient gas "deliverability" to meet all recently expressed peak-period demands. The illiquidity problem is expressed as the apparent lack of counterparties with which to contract and obtain gas supplies other than at predominantly morning hours of week days. Coordination stems from a lack of pipeline scheduling opportunities to schedule potentially available supply, through available capacity, and get that supply to generation locations. The deliverabilty problem is the expressed lack of capacity, or the under-utilization of supplemental gas supply sources to serve generation and other peak-period demands. For instance, insufficient capacity could be addressed to the extent supplemental supplies (i.e., LNG and to some extent propane-air facilities of New England LDC's) meet demand otherwise requiring west-to-east pipeline capacity utilization. In addition, gas supplies from the Everett and/or Canaport LNG terminals could also feed demands "at the ends of the lines" otherwise requiring west-to-east pipeline capacity utilization. Were there reliable supplies from these sources, while there may still be an "illiquidity" problem there would not be a "deliverability" problem.

Solution:

The gas market refinements set forth below (with companion adjustments as needed to electric markets) address the current absence of delivered-gas price certainty (i.e., "illiquidity", "coordination", and to some degree "deliverability" issues) facing most gas-electric grids especially in the organized regional ISO/RTO markets. Attached as Appendix B is an approximation of the additional gas and electric capacity which would be facilitated by the market design refinements discussed below.

Addressing Illiquidity:

Promptly addressing illiquidity will also facilitate solutions for the category of "coordination" challenges and will distinguish the somewhat conflated issues of illiquidity from coordination. The goal of the immediate and intermediate time frame solutions discussed below is to quickly address the current issues being experienced in the gas and electric markets in New England including through measures that are possibly temporary or pilot-scale offerings.

To begin addressing this illiquidity, the gas market can, even on a temporary and/or "pilot" limited term basis, offer services within electric markets while long-term solutions are formulated and fully vetted. These mechanisms are intended to be both: 1) compensatory to those that provide the assets (contractual and physical) enabling these services; and, 2) to provide transparent price signals to the market in order that these and possibly other mid and long-term solutions can respond to more accurate price signals.

Immediate Market Fixes:

Within the current NAESB Scheduling cycles, encourage and establish the following Pipeline Service and remove impediments to its implementation that may exist within the electric market(s) within which this service is provided:

1) Take and Replace/Pack and Pull
   a. Once nominations and confirmations are conducted for the next cycle (and before scheduled quantities are reported):
      i. Pipeline offers to sell capacity (for a per unit and total price $$) of a specific quantity and at specific location(s) (posted hourly) of available "Take" with a pipeline specified (offsetting) location(s), time and quantity of commencement of "Replace"; likewise,
      ii. Pipeline offers to sell capacity (for a per unit and total price $$) of a specific quantity (posted hourly) of available "Pack" with a pipeline specified (offsetting) location(s), time and quantity of commencement of "Pull."
      iii. "Take" is where a party takes additional delivery from of gas the pipeline; and, "Pack" is where a party does not take currently scheduled delivery of gas from the pipeline.
      iv. In both cases the times, quantities and location(s) are firm requirements of the respective parties. In addition,
         1. The pipeline's "charge" for identified transaction(s) is no less than fuel and minimum commodity charge and there is no limit on the charge that can be levied by the pipeline
         2. Within a time frame (to be determined) the pipeline posts transaction(s) and with respect to such transactions it posts whether capacity path utilized was:
            a. "operationally available" or "unsubscribed"; and,
            b. The associated quantity(ies), hour(s), path(s) and charge(s) by transaction
   b. The only regulatory action required to implement this service would be a finding by the FERC that the charge for this service was market based and not subject to maximum price

regulation. In essence the current maximum daily PAL rate would not apply to this firm service. Posting of the related transaction particulars (set forth in general above) would be a requirement so as to promote transparency and send price signals for the market to respond to.

c. To the extent this service is offered in the current Timely cycle, no changes to electric market rules in the Day-Ahead market are believed to be needed.
d. To the extent this service is offered during what are generally "off-hours" of the gas commodity market, in conjunction with the establishment of the foregoing gas market service, it may be necessary to remove barriers in some ISO/RTO markets that may operate today to prevent generators from incorporating into their bids into the day ahead market the cost impact(s) they incur due to transacting the above service in real-time.

Intermediate Market Fixes:

Within the current NAESB Scheduling Cycles, encourage and establish the following Pipeline Service and remove impediments to its implementation that may exist within the current gas regulatory construct and within the electric market(s) within which this service is provided:

1. Pipeline cleared Bid-Offer Merchant Service
    a. Sellers (physical) (including other interstate pipelines) who have given the subject pipeline permission to control/specify their flow of gas and who have incremental supply deliverability would log into the subject pipeline's system and provide quantity and price for incremental volumes in hourly quantities (i.e., offer a price per quantity tranche for a specific delivery location).
        i. Sellers would update their tranche information at each nomination deadline for each cycle (to the extent it changes)
    b. Buyers (physical end-users or other interstate pipelines who would be taking title to gas sold to them by the pipeline either at a consumption location or into capacity controlled by or under contract to them for ultimate consumption) that are requiring supply and who have incremental supply requirements would log into the subject pipeline's system and provide quantity, price and location (and contract ID where applicable) for incremental volumes in hourly quantities (i.e., bid a price per quantity and location tranche)
        i. Buyers to update their tranche information at each nomination deadline for each cycle (to the extent it changes)
    c. Once nominations and confirmations for the current cycle are conducted, then, to the extent of available Physical Capacity for the hour(s) within the subject cycle, the pipeline evaluates the quantity(ies), prices and path(s) and the pipeline generates transaction(s) to satisfy servable demand within such cycle.
        i. Pipeline's "charge" for identified transaction(s) is no less than fuel and minimum commodity charge and there is no limit on the charge that can be levied by the pipeline
        ii. Within a time frame to be determined, the pipeline posts transaction(s) and with respect to such transaction(s) it posts whether capacity path utilized was:
            1. "operationally available" or "unsubscribed"; and,
            2. The associated quantity(ies), hour(s), path(s) (i.e., receipt location(s), path(s) and delivery location(s)) and charge(s) by transaction
    e. Required regulatory findings are set forth in the Appendix A but generally would be pursuant to temporary authority granted under 18 CFR 284.261 thru 284.271 and which generally would include: FERC permitting such sales transactions, a finding by the FERC that the charge for this service was market based and not subject to maximum price regulation. Posting of the related

transaction particulars (set forth in general above) would also be a requirement so as to promote transparency and send price signals for the market to respond to.

f. To the extent this service was offered in the current Timely cycle, no changes to electric market rules in the Day-Ahead market are believed to be needed.
g. To the extent this service is offered during what are generally “off-hours” of the gas commodity market, in conjunction with the establishment of the foregoing gas market service, it may be necessary to remove barriers in some ISO/RTO markets that may operate today to prevent generators from incorporating into their price offerings to the grid the cost impact(s) they incur due to transacting the above service in real-time.

2. Interconnecting Pipeline Participation in Bid-Offer Stack as Seller
    a. As mentioned above, and repeated for clarity we propose to allow pipelines to sell:
        i. supplies they acquire through an offer mechanism (outlined above) and/or,
        ii. their own working and operational gas
        iii. into the Bid-Offer-Stack auctions of an interconnected pipeline thereby increasing the amount of gas available for auction.
    b. Required regulatory findings and reporting would be the same as outlined in general above and specifically in the Appendix A.

3. Pipeline Operated Released Capacity Aggregation
    a. Pipeline would offer to purchase from Shippers holding released capacity (generally applicable here to marketers serving retail load) such shipper’s un-nominated capacity (a pipeline specified “up to” amount) into a pipeline operated pool at either a posted price or under a revenue sharing mechanism outlined below.
    b. Then, that capacity could be sold in an aggregated bundle by the pipeline on an hour at a time or day at a time basis at any price (chosen by the pipeline) to any shipper with confirmable gas to fill it and make delivery to a buyer. Here a revenue sharing could be outlined with the releasers.
        i. Alternatively, the pipeline could use this un-nominated capacity to operate the “bid-stack” market identified above
            1. A wrinkle in this “bid-stack” model could be to share with the participating releasing capacity holders a percentage (say 50%) of the net revenue (i.e., sales price less gas, commodity and fuel)
    c. Required regulatory actions include: FERC Finding that pipeline can retain revenues from “mark-up” of aggregated bundle of capacity. To the extent such “bundled aggregate of capacity” is used to make bundled sales or aggregated sales of capacity at a mark-up, FERC finding permitting such transactions and finding that the charge for this service was market based and not subject to maximum price regulation. Posting of the related transaction particulars (set forth in general in applicable “Take and Replace” or “Bid-Stack” models above (and as applicable in Appendix A) would also be a requirement so as to promote transparency and send price signals for the market to respond to.
    d. To the extent this service was offered in the current Timely cycle, no changes to electric market rules in the Day-Ahead market are believed to be needed.
    e. To the extent this service is offered during what are generally “off-hours” of the gas commodity market, in conjunction with the establishment of the foregoing gas market service, it may be necessary to remove barriers in some ISO/RTO markets that may operate today to prevent generators from incorporating into their price offerings to the grid the cost impact(s) they incur due to transacting the above service in real-time.

Algonquin, Iroquois and Tennessee Specific Intermediate Solution Offering:

1) Both Iroquois and Algonquin permit 6% hour takes on a subset of otherwise ratable take contracts. The proposal here is to permit shippers with those 6% hour capabilities to release specified hourly amounts of just the extra hourly deliverability of those contracts to other shippers.
   a) In total we estimate that there is on the Algonquin system alone approximately 13,800 to 16,000 Dth/hour of this capacity which at a 7,000 heat rate, if all were available (which it would not be) could power approximately 2,000 MW of generation.
   b) The Iroquois 6% hour capacity that could be projected onto Tennessee is approximately 3,000 Dth/hour or enough to power just over 400 MW with a 7,000 heat rate.
   c) The Iroquois 6% hour that could be projected onto Algonquin is another approximately 400 Dth/hour or enough to power another 50+MW of generation.

Summation of Immediate and Intermediate Solution sets:

At the core of all proposed solutions outlined above, both immediate and intermediate, the problems these measures seek to solve are:

1. Current perceived illiquidity of the gas market; (i.e., add certainty to gas pricing before Electric market settlement),
2. Better utilization of existing Firm capacity – the potential magnitude of which is discussed in Appendix B; and,
3. With respect to the "Bundled Aggregate" proposal, in the Northeast in particular, there are a large number of small to mid-sized retail marketers with lots and lots of little pieces of capacity, much of which they do not need to use every day and which are also too small in their "leftovers" to individually assist in the getting gas to generation markets. Aggregating these little pieces that are available on a day at a time basis into marketable blocks would improve existing firm transportation utilization, predictability (day at a time) and generate revenues for both the pipelines and shippers with small and irregular sized un-used capacity.

Long Term Solutions[1] – Step-Wise Implementation

Following the above described market mechanisms addressing "illiquidity", Skipping Stone proposes a number of step-wise changes aimed at improved coordination of the gas and electric markets.

Eastern and Western Energy Days

First among these is to change and align the gas and electric "Energy Days." We propose the introduction of an "Eastern Energy Day" and a "Western Energy Day" for both gas and electricity markets in these respective regions. These days would commence at 6:00 AM in each of the Pacific and Eastern Time Zones with the Mountain and Central commencements at 7:00 AM and 5:00 AM local time respectively. At first, the existing scheduling deadlines for next day service in both the gas and electricity markets, including either of the jump-ball New England proposals, could remain `as-is`. The two industries could then work through both the proposed market operational changes for gas nominations and electricity settlement and physical operational changes for scheduling timelines intended to increase responsiveness and coordination frequency; see White Paper for details.

The benefit to moving the gas day earlier by 4 Hours Eastern and 3 hours Central, 1 hour Mountain and 1 hour Pacific we better align the start of the Gas Day with the start of the morning burn across the country. This

[1] Derived from the Skipping Stone White Paper for which CLF is not taking a position at this time.

means that instead of an LDC having to guess on Monday what Wednesday morning's burn will be they will be able to nominate on Monday for Tuesday and Tuesday for Wednesday. Likewise by moving the electric grid's electric day to 6 hours later in each of Eastern and Pacific and 5 hours later in each of Central and Mountain, they will be better able to coordinate the scheduling of their next day's fuel with the gas industry's start. This sets the stage for better market and operational coordination through the measures outlined below.

Move Electric Day Forecasts and Capacity Release to Morning – Electric Market Day-Ahead to Early Afternoon and Nominations to Late Afternoon

While we have proposed specific timelines for the Electric and Gas Market's economic and operational activities that we believe are workable and on which there may be supporters and detractors, the important conceptual proposals are as follows:

1) Forecasts in organized markets (electric) should be moved to early morning today for tomorrow's respective Energy Day's
2) Capacity Release Markets (gas) for capacity that can be used in timely nominations for tomorrow should be moved to after electric market forecasts
3) Electric Market Clearing should be moved to after Capacity Release Market settles, and,
4) Timely Gas nominations (the gas market's commodity clearing deadline for tomorrow) should be moved to after Electric Market for day-Ahead settles.

Once these two markets are economically synchronized, as proposed above, additional Capacity Release and nomination cycles can further the goals of mutual coordination and optimal use of existing facilities. Moreover, with price formation and commensurate market responses coordinated between these two markets, all sorts of additional market innovations and tools have a solid operational and well-coordinated base to improve upon.

Firm is Firm

In the White Paper we published, we proposed that a fuel neutral "Firm is Firm" redefinition of firm power be introduced into the Day-Ahead electric markets. While most bi-lateral and vertically integrated electric markets have state set IRP rules requiring firm capacity to support electric generation, this is not the case in the organized ISO/RTO markets. In ERCOT, there are economic incentives acting on generators to perform (or reduce production). These take the form of what are effectively "make good" balancing rules requiring purchases in real-time to come in line with market constraints. In the other organized ISO/RTO markets this performance requirement (enforced through balancing rules) is largely absent.

Our proposal that Firm be Firm, and that this apply nationwide was driven largely by what we saw as the likely operation of the "law of unintended consequences" if "Firm is Firm" were to apply in only within organized markets. We saw the potential for future siting of generation outside of organized markets in order to avoid organized market rules and that this would be an uneconomic consequence of uneven applicability of Firm is Firm.

While from an economic, reliability, and market operations point of view, a nationwide *Firm is Firm* may be the ideal, enhanced state and federal coordination might well accomplish nearly the same objectives - reliability, coordination, synchronization and accurate price signals. Enhanced state and federal coordination would address diligent monitoring and review of organized market rules (in particular those pertaining to price caps), rules and protocols pertaining to imports that compete with in-market participants and reliability based IRP and forward market forecast requirements.

Appendix A

Modifications to 18 CFR 284.262, 284.263, 284.264, 284.266, 284.267, 284.269, & 284.270

For a “to be determined” (i.e., FERC determined) period of time and using the Authority the FERC has under 284.271 the Commission would also do the following with respect to the enumerated sections:

1) 284.262 (4) would be amended to include maintenance of or improvement to reliability of the subject geographical electric grid whose reliable operations depend on natural gas for generation of power.
    a. Projected level of service definition amended to remove the word “solely”
    b. Emergency natural gas transaction (2) is modified to remove 60 days and insert the duration of the temporary authority granted by FERC
2) 284.264 (a) (2) is modified to require the interstate to notify FERC of the commencement of this temporary service
3) 284.264 (a) (5) is waived
4) 284.264 (b) (i) is modified to read within 48 hours of commencing service under this temporary authority
5) 284.266 is waived in favor of the reporting of transaction details as proposed
6) 284.267 is waived in favor of the reporting of transaction details as proposed
7) 284.269 is waived in favor of the reporting of transaction details as proposed
8) 284.270 is waived in favor of the reporting of transaction details as proposed

Conceptual Framework for Merchant Service required reporting:

For each Buy/Sell Transaction:

A. Identity of Seller
B. Quantity purchased (by price, location and time period tranche - including price per Dth)
C. Location of purchase
D. Time Period of purchase (i.e., beginning date-time and ending date-time)
E. Max and Average Hourly Quantity of purchase
F. Identity of Buyer
G. Quantity Sold (by price, location and time period tranche - including price per Dth)
H. Location of Sale
I. Time Period of Sale - including price per Dth
J. Max and Average Hourly Quantity of Sale
K. Path utilized to effectuate transaction
L. Capacity Type (i.e., unsubscribed/operational/other – specify)

Appendix B

Magnitude of Immediate and Intermediate Solutions

The potential magnitude of additional near term demand which can be met by Algonquin and Tennessee within the ISO-NE market is significant. In the accompanying charts, the data from this past winter suggests that as much as 30 Bcf or more of increased gas supply for electric generators could be met through introduction of one or more of the proposed interim solutions (i.e., Take and Replace/Pack and Pull, and/or Pipeline as Merchant Services). Of course, there will be days when no amount of new services will be able to cause gas to flow in excess of capacity. Nonetheless, recent data indicate that such services can substantially reduce illiquidity and increase deliverability of gas for power generation.

Making assumptions that: 1) the pipelines could offer such services up to at least 85% of contracted firm capacity, 2) demand for gas to serve generation was evident, and further assuming 3) that all supply would have to come from the west (i.e., relying on no incremental Sable Island or LNG beyond this past Winter's quantities) Tennessee (TGP) and Algonquin (AGT) west-sourced supply could provide an additional 27 Bcf to meet that demand (8.8 Bcf TGP and 18.5 Bcf AGT).

If one were to further assume that near term electricity market refinements supported secondary fuel at oil price levels and such price levels would call forth LNG supplies, then as much as 65+ Bcf of demand could be met with current facilities (at the 85% of contracted capacity level). While it is unlikely that generation will demand gas every day (or every hour of every day) that such capacity might be utilized, which is one reason for the 85% of capacity limit chosen for the analysis, nevertheless the opportunity is significant and would provide a greater level of supply to meet generation needs in New England.

The displaced or avoided oil burn (assuming No.2 fuel oil) could be between 4.6 and 11.2 Million Bbls.

The 4.6 Million Bbl level being achieved with west-source supplies and the 6.6 Million Bbl higher level (11.2 MM Bbls) being comprised primarily of LNG supplies. Assuming the incremental displacement of 6.6 MM Bbls of oil is No.2 oil, then this translates into ~38 Bcf of LNG or or somewhere between 12 and 15 cargoes) to achieve higher levels of *avoided oil procurement/consumption*.

Methodology of Algonquin (AGT) and Tennessee (TGP) Zone 6 Contracted Receipts Vs. Scheduled Receipts Charts:

AGT Studied Period: Data for Scheduled AGT Flows from Dec 15, 2012 thru April 15, 2013 was available and used.

Contracts on AGT:

With the exception of 6 Firm contracts on AGT (out of 130) the contracted firm receipt quantity under the contracts equal the Maximum Daily Transportation Quantity (MDTQ). AGT is a "Fully subscribed pipeline". This means that totaling all the Firm receipt quantities contracted for on the pipeline can be used to assess the firm capacity of the pipeline.

Location of Receipt Points on AGT:

AGT receives the bulk of its supplies at the western end of its system (i.e., NJ, NY and SW CT). The remainder of its receipts can generally be referred to as east-end receipts (MA & a little in far SE CT). By categorizing AGT's receipt points as East or West and applying that to both contracted and schedule quantities one gets a picture of AGT's system utilization relative to its capability.

Scheduled Quantities on AGT:

AGT is required to post aggregated scheduled quantities on the pipeline multiple times per day. One of the daily postings is the End of Day Scheduled Quantity which reflects the total scheduled quantities at each location for the then ending "Gas Day". By downloading that information for each day, and, comparing the sum of receipts to contracted capacity (West and East respectively), one gets a good picture of how the pipeline is both being used and also could be, incrementally, used.

What The AGT Charts Tell Us:

The charts tell us that if generators had demand for gas on days where there was less than 85% of capacity utilized, and up to that 85% was "demanded" that there could have been as much as 36 Bcf of gas made available (~ 6.2 Million Bbls of No.2 oil equivalent) for generation, had there been in place tools to make utilization of that capacity possible. In addition, as can be seen from the charts (and analyzing the underlying data) there were only 7 days when the total system was scheduled above 85% of contracted levels.

If there were no incremental supplies available in the east (i.e., LNG, MN&E, or Tennesssee) then using the same assumptions as to demand as used above, there still could have been as much as 18.5 Bcf (~3.2 Million Bbls of No.2 oil equivalent) available for generation. Additionally, the scheduled west receipts only exceeded 85% of contracted firm on 5 days of the studied period.

Significance of East Receipts on AGT:

Even though contracted firm receipts of gas on the east end are only ~0.5 Bcf/d or~86,000 Bbls/d of No. 2 oil equivalent (compared to ~1.727 Bcf/d of firm west receipts or ~300,000 Bbls/d of No.2 oil equivalent), almost every Dth of additional gas that can be delivered and burned in the east can be accepted due the hydraulics of pipelines (east receipts destined for middle or west locations take the place of west receipts having to move all the way to the east).

Methodology of TGP Zn 6 Contracted Capacity Vs. Scheduled Capacity charts:

TGP Studied Period: Data for Scheduled TGP Flows from Jan 1, 2013 thru April 22, 2013 was available and used.

Contracts on TGP:

On TGP the contracted firm MDTQ (Maximum Daily Transportation Quantity) equals the Firm delivery obligation of the pipeline. In Zone 6 the sum of the MDQ's of specific delivery points under contracts will often exceed the MDTQ, as does the sum of MDQ of receipts for some contracts. TGP is a "Fully subscribed pipeline." This means that totaling all the Firm MDTQ contracted for in Zone 6 on the pipeline can be used to assess the firm capacity of the pipeline in Zone 6.

Location of Receipt Points on TGP:

TGP receives the bulk of its supplies west of its Zone 6 (i.e., LA thru NY and far SW CT). The remainder of its receipts can generally be referred to as east-end receipts (Dracut, MA from MN&E and Everett, MA (LNG)). By categorizing TGP’s contracts as West Sourced or East Sourced and applying that to both contracted and scheduled quantities one gets a picture of TGP’s system utilization relative to its capability.

Scheduled Quantities on TGP:

TGP is required to post aggregated scheduled quantities on the pipeline multiple times per day. One of the daily postings is the End of Day Scheduled Quantity which reflects the total scheduled quantities at each location for the then ending “Gas Day”. By downloading that information for each day, and, comparing the sum of deliveries into Zone 6 less East receipts as well as the sum of East Receipts one gets a good picture of how the pipeline is both being used and also could be, incrementally, used.

What The TGP Charts Tell Us:

The charts tell us that if generators had demand for gas on days where there was less than 85% of capacity utilized, and up to that 85% was “demanded” that there could have been as much as 33 Bcf of gas made available (~ 5.7 Million Bbls of No.2 oil equivalent) for generation, had there been in place tools to make utilization of that capacity possible. In addition, as can be seen from the charts (and analyzing the underlying data) there were only 10 days when the total Zone 6 system was scheduled above 85% of contracted levels.

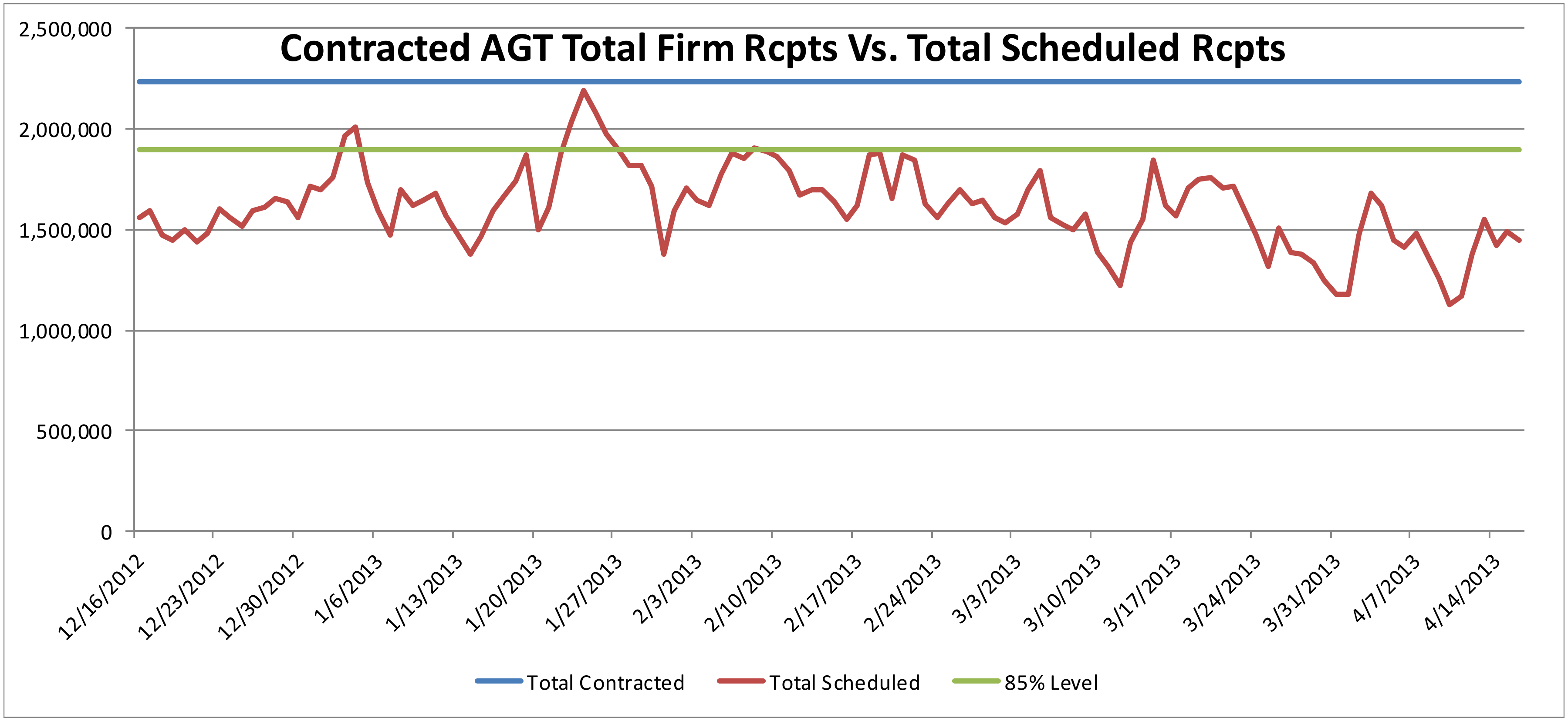
If there were no incremental supplies available in the east (i.e., LNG or MN&E) then using the same assumptions as to demand as used above, there still could have been as much as 8.8 Bcf (~1.5 Million Bbls of No.2 oil equivalent) sourced in the western parts of TGP available for generation. This is the case even though the scheduled deliveries from west sourced receipts exceeded 85% of contracted firm on 70 days of the studied period.

Significance of East Receipts on TGP:

Even though contracted firm receipts of gas on the east end are only ~0.42 Bcf/d or~73,000 Bbls/d of No. 2 oil equivalent (compared to ~1.423 Bcf/d of firm west receipts or ~246,000 Bbls/d of No. 2 oil equivalent), almost every Dth of additional gas that can be delivered and burned in the east can be accepted due the hydraulics of pipelines (east receipts destined for westerly locations yet burned in the east take the place of west receipts having to move all the way to the east).

LNG as a Component of East Receipts for Either AGT or TGP:

This means that even on the needle peak days, with very few, if any, exceptions, gas received in the east (~Worcester County MA eastward) can serve markets and replace oil. In short, having a reserve of gas in LNG tanks of 15 to 38 Bcf (~ 5 to 13 LNG cargoes) would serve the same purpose as having an additional 2.6 to 6.5 Million Bbls of No. 2 oil in inventory. Moreover, if the LNG were advance purchased at close to oil prices it would be “pulled to the respective terminals” and available to meet demand.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2,000,000
1,500,000
1,000,000
500,000
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12/23/2012
12/30/2012
1/6/2013
1/13/2013
1/20/2013
1/27/2013
2/3/2013
2/10/2013
2/17/2013
2/24/2013
3/3/2013
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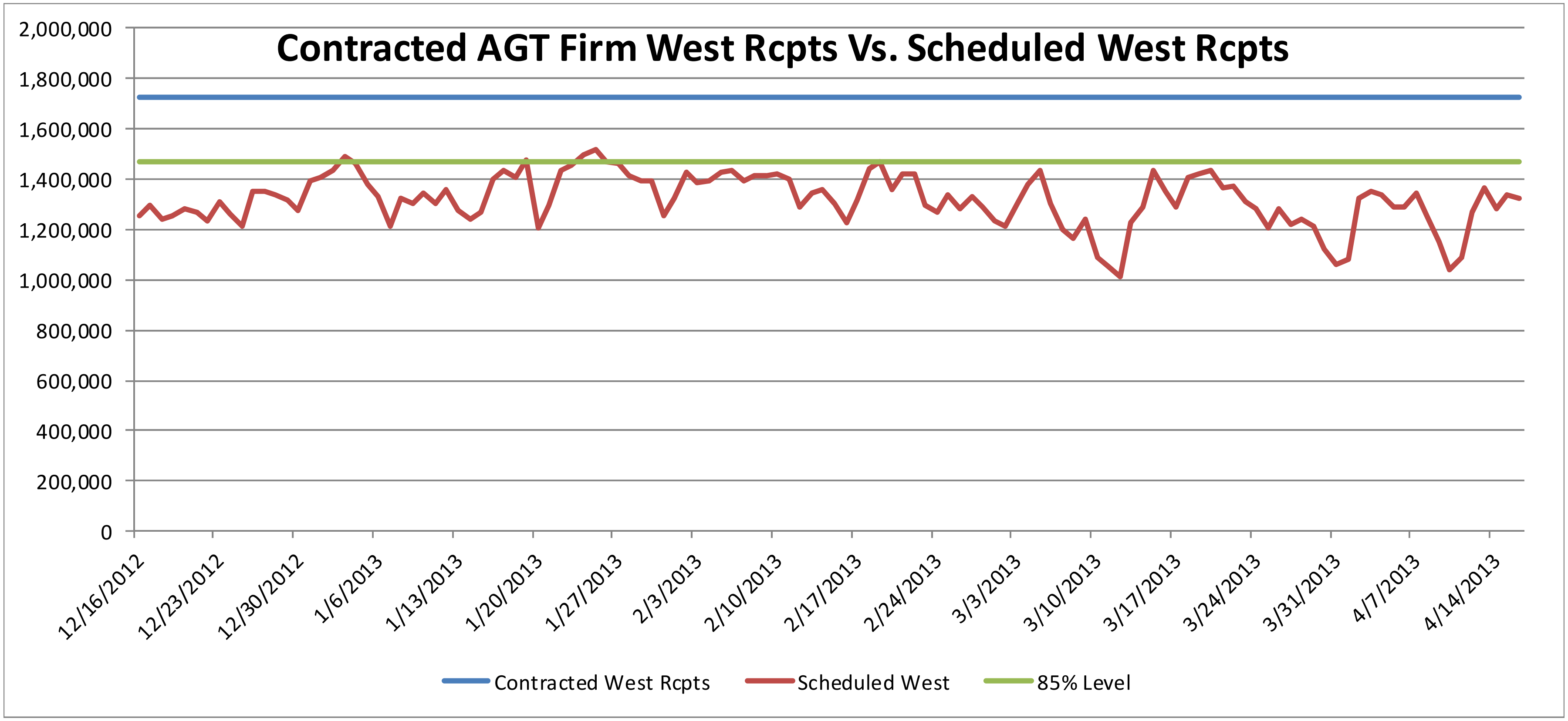
Total Contracted
Total Scheduled
85% Level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2/17/2013
2/24/2013
3/3/2013
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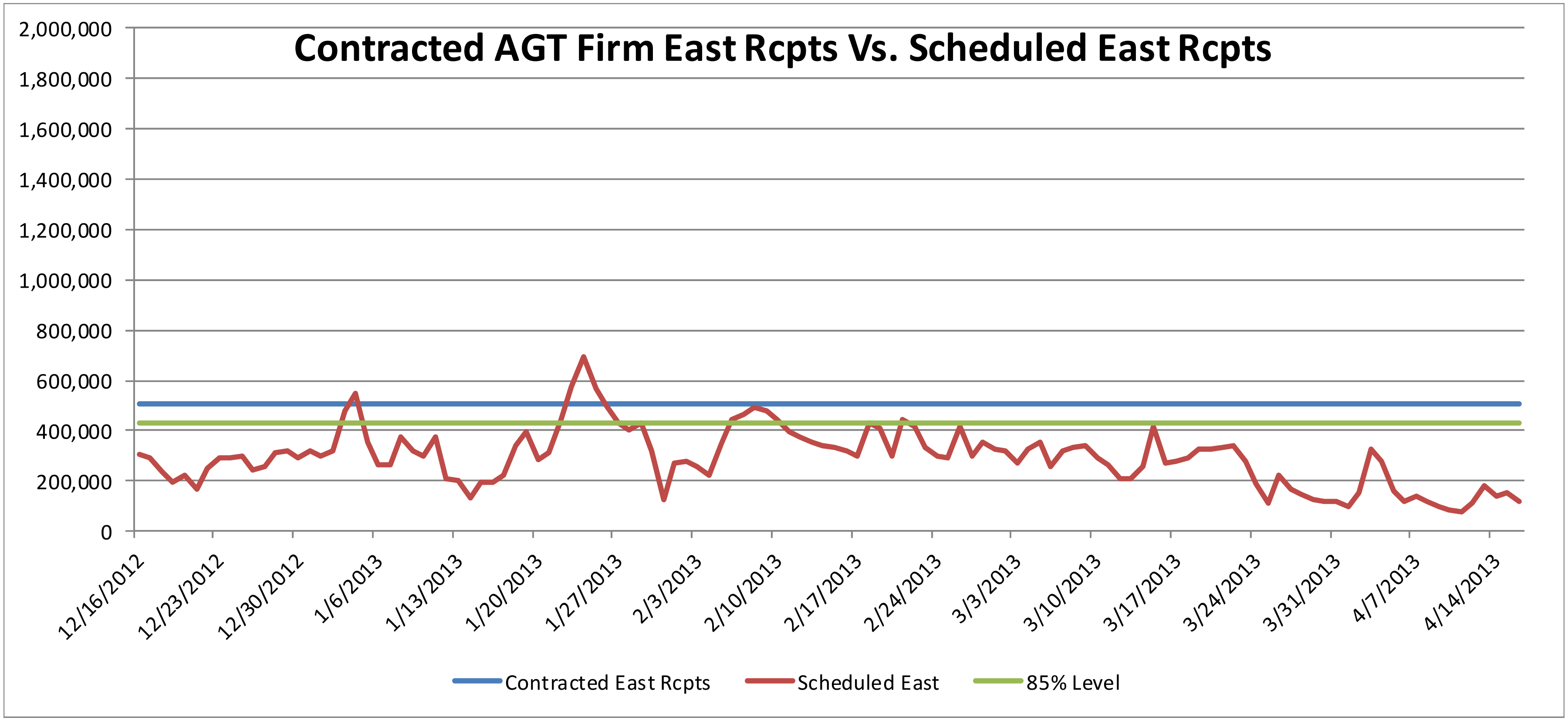
85% Level



Contracted AGT Firm East Rcpts Vs. Scheduled East Rcpts
2,000,000
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1,600,000
1,400,000
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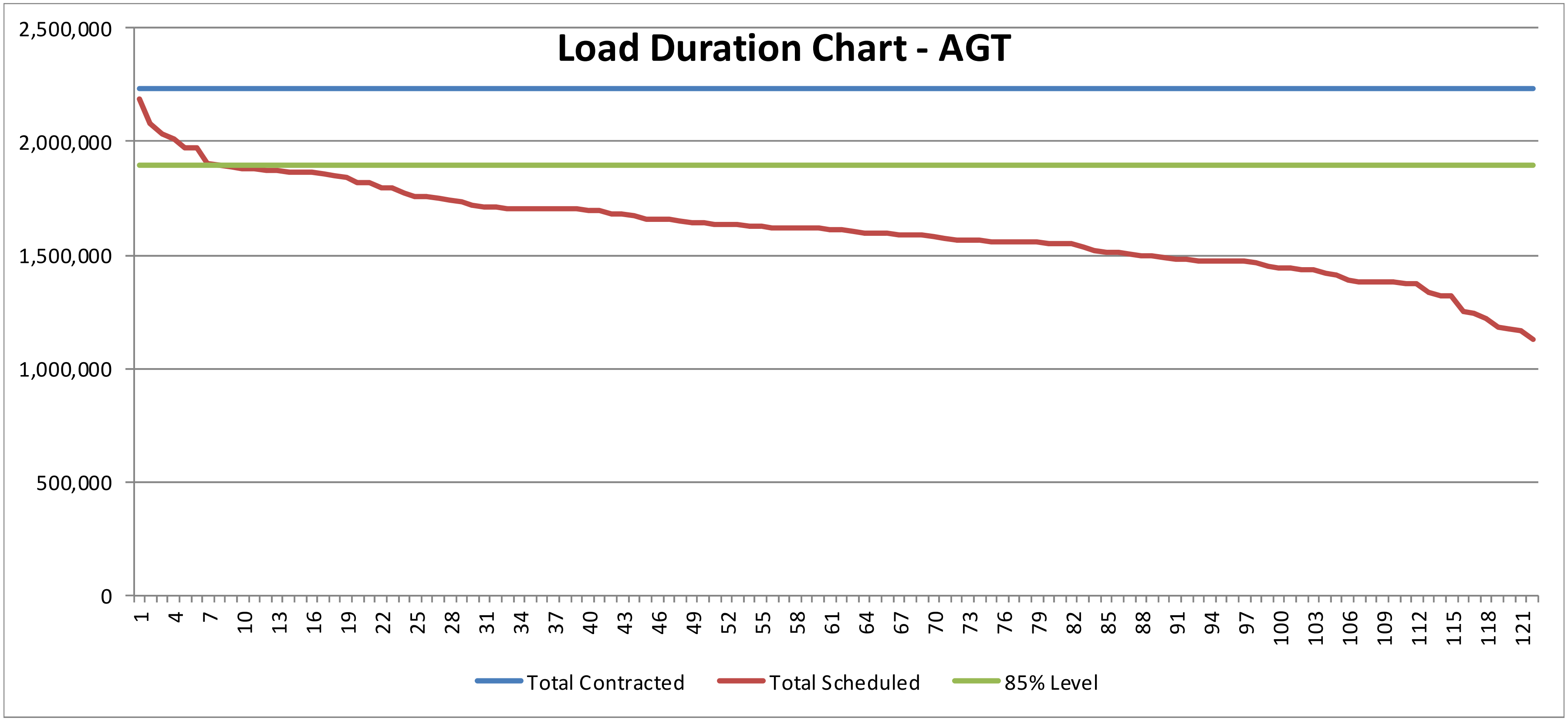
Contracted East Rcpts
Scheduled East
85% Level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2,000,000
1,500,000
1,000,000
500,000
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1
4
7
10
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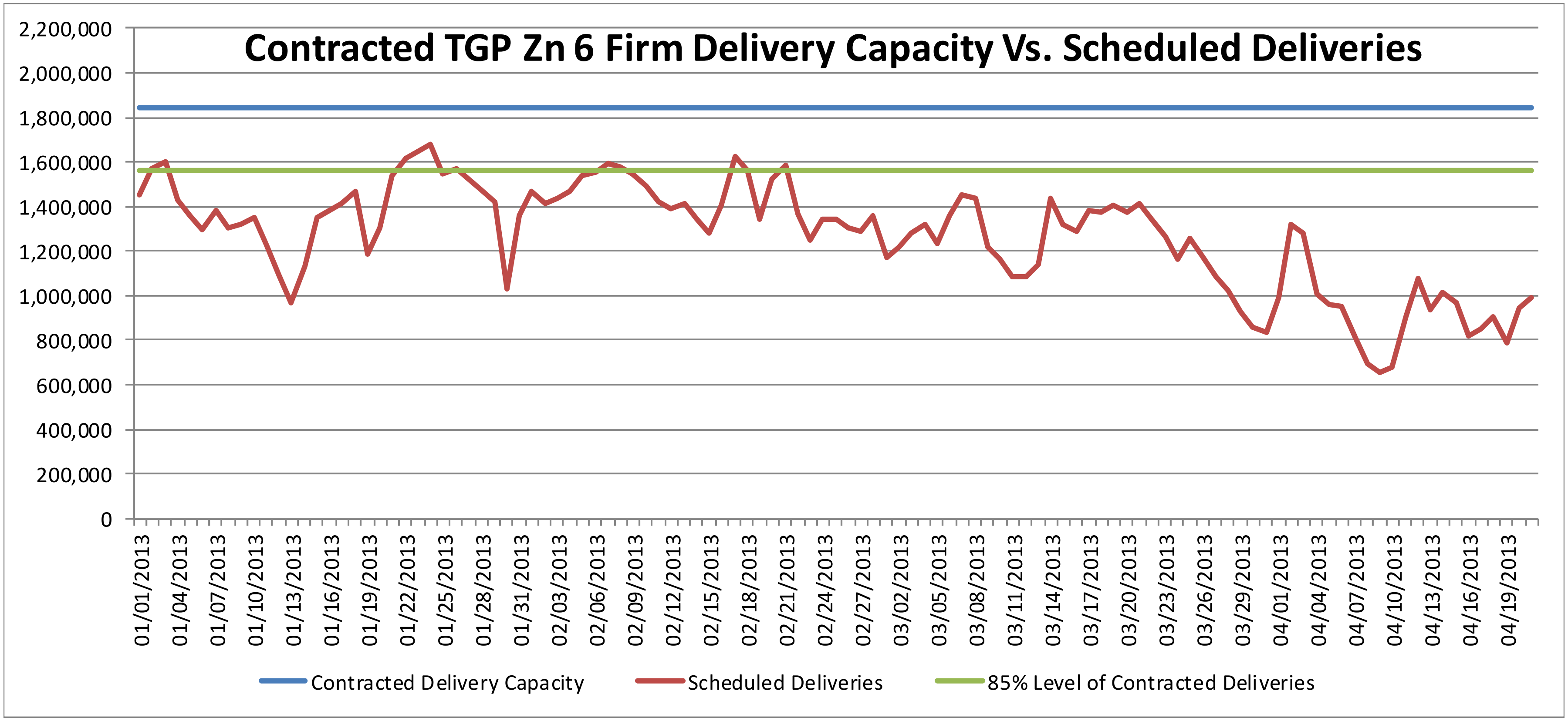
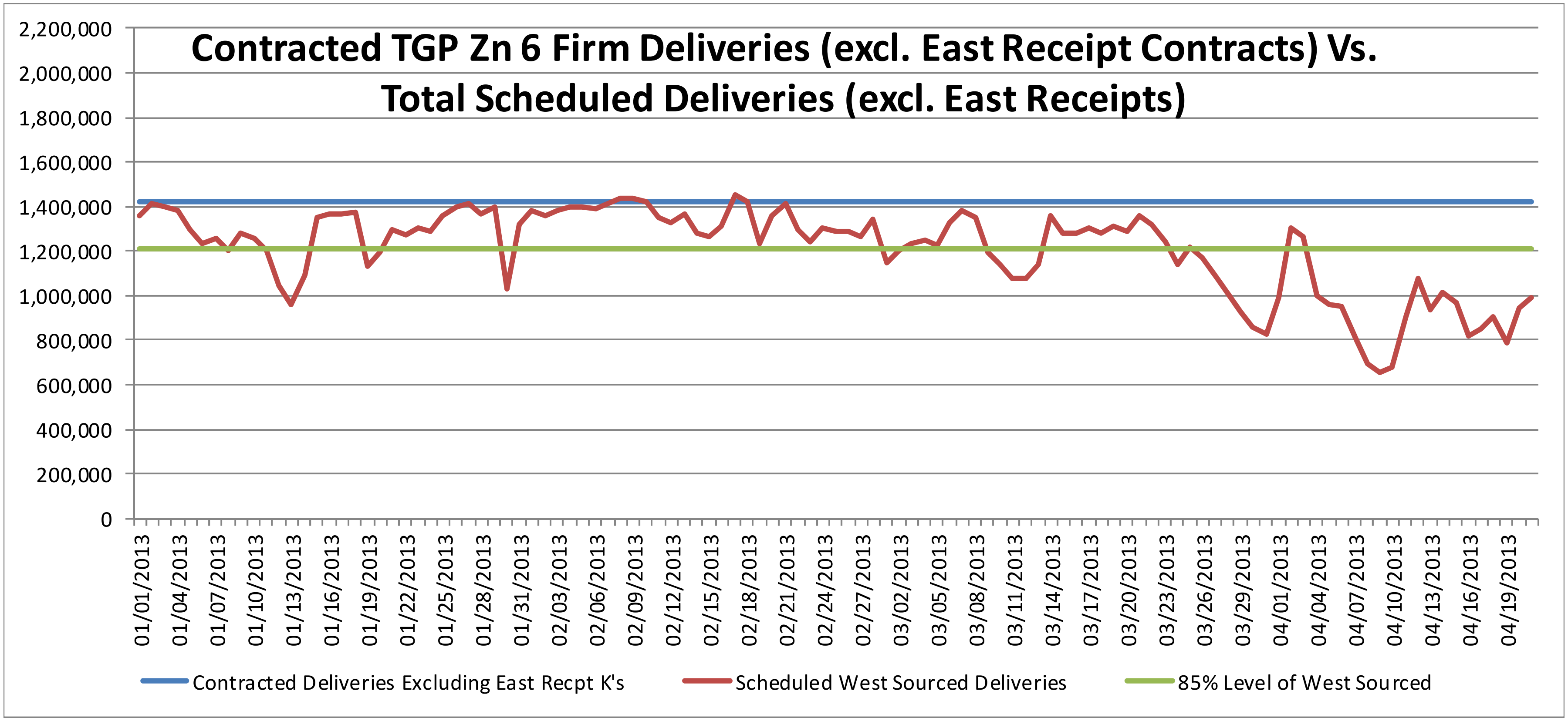
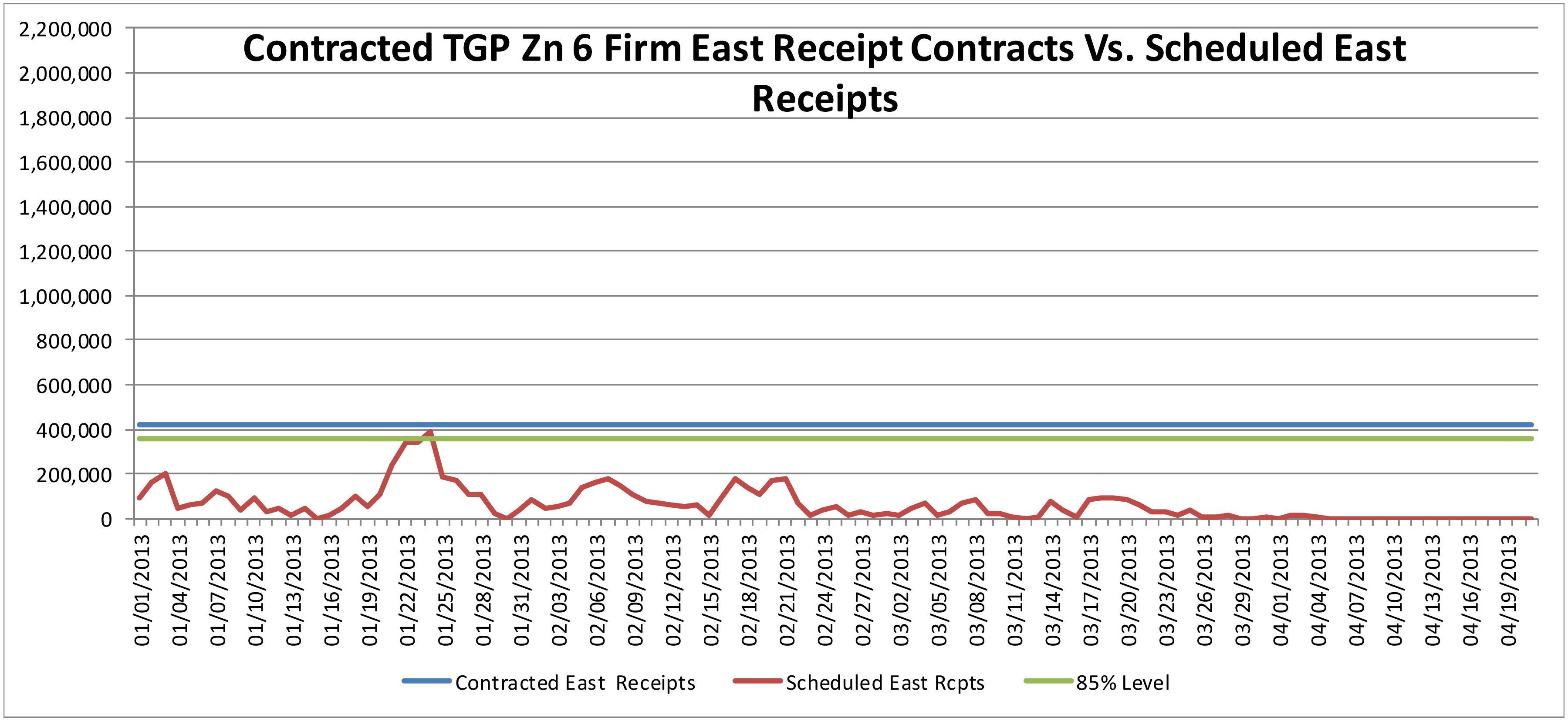
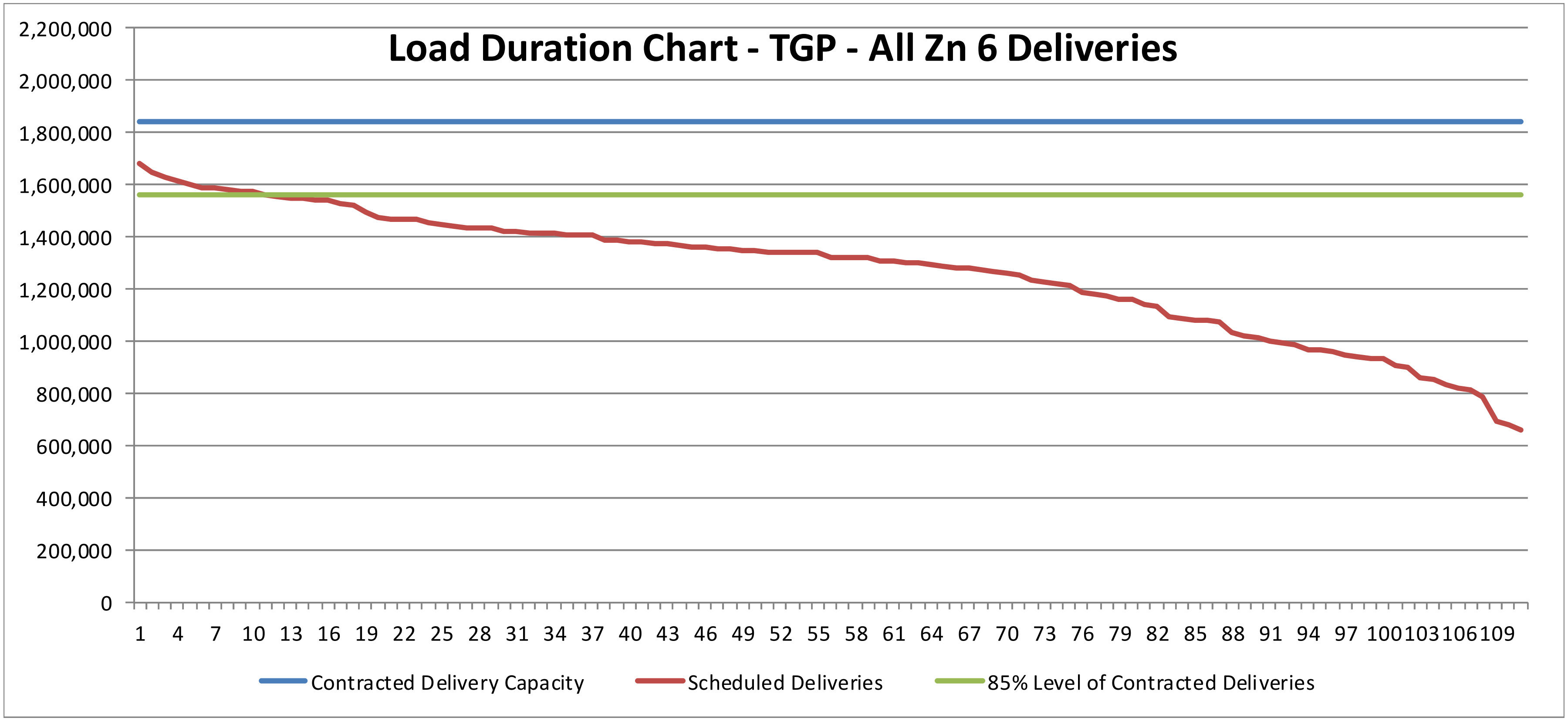
16
19
22
25
28
31
34
37
40
43
46
49
52
55
58
61
64
67
70
73
76
79
82
85
88
91
94
97
100
103
106
109
112
115
118
121
Total Contracted
Total Scheduled
85% Level

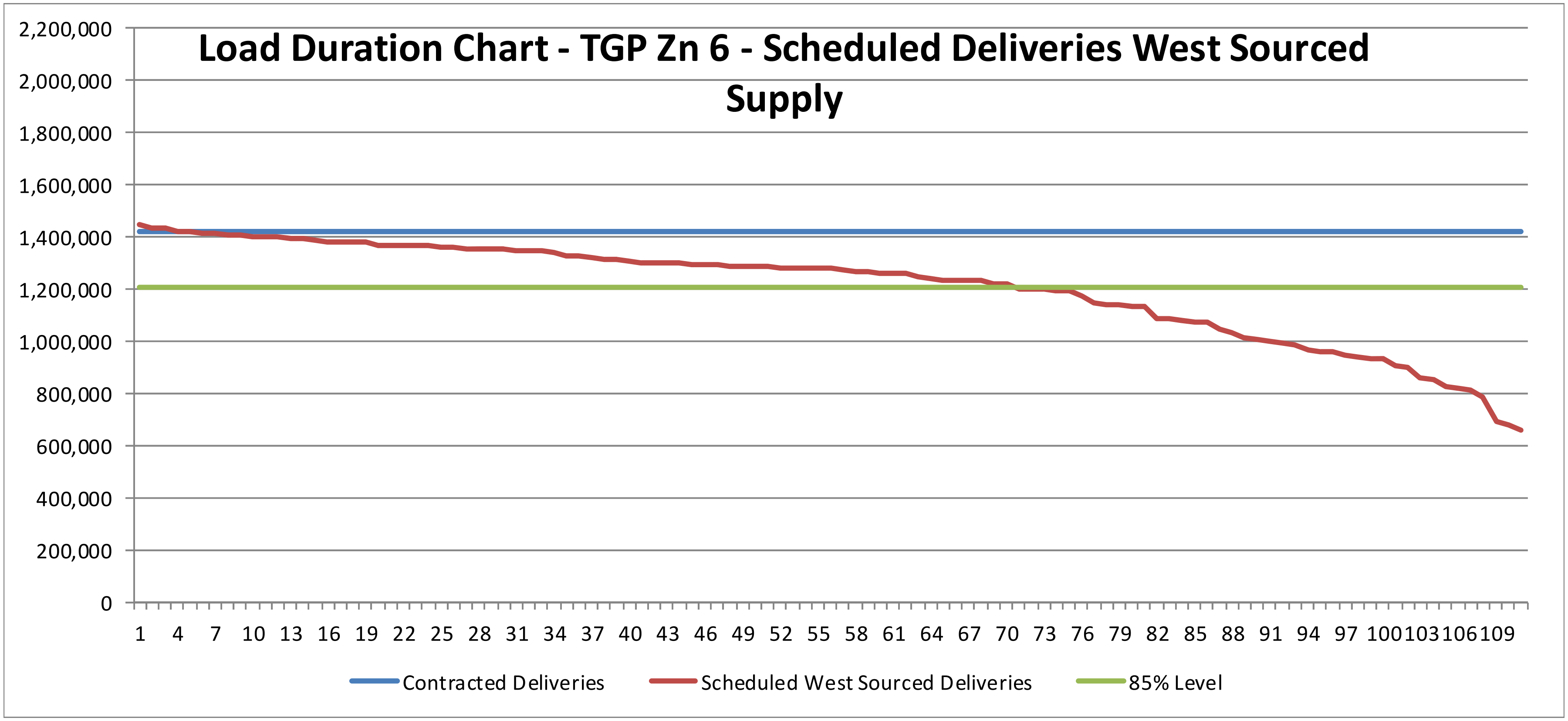

Contracted TGP Zn 6 Firm Delivery Capacity Vs. Scheduled Deliveries
2,200,000
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
01/01/2013
01/04/2013
01/07/2013
01/10/2013
01/13/2013
01/16/2013
01/19/2013
01/22/2013
01/25/2013
01/28/2013
01/31/2013
02/03/2013
02/06/2013
02/09/2013
02/12/2013
02/15/2013
02/18/2013
02/21/2013
02/24/2013
02/27/2013
03/02/2013
03/05/2013
03/08/2013
03/11/2013
03/14/2013
03/17/2013
03/20/2013
03/23/2013
03/26/2013
03/29/2013
04/01/2013
04/04/2013
04/07/2013
04/10/2013
04/13/2013
04/16/2013
04/19/2013
Contracted Delivery Capacity
Scheduled Deliveries
85% Level of Contracted Deliveries

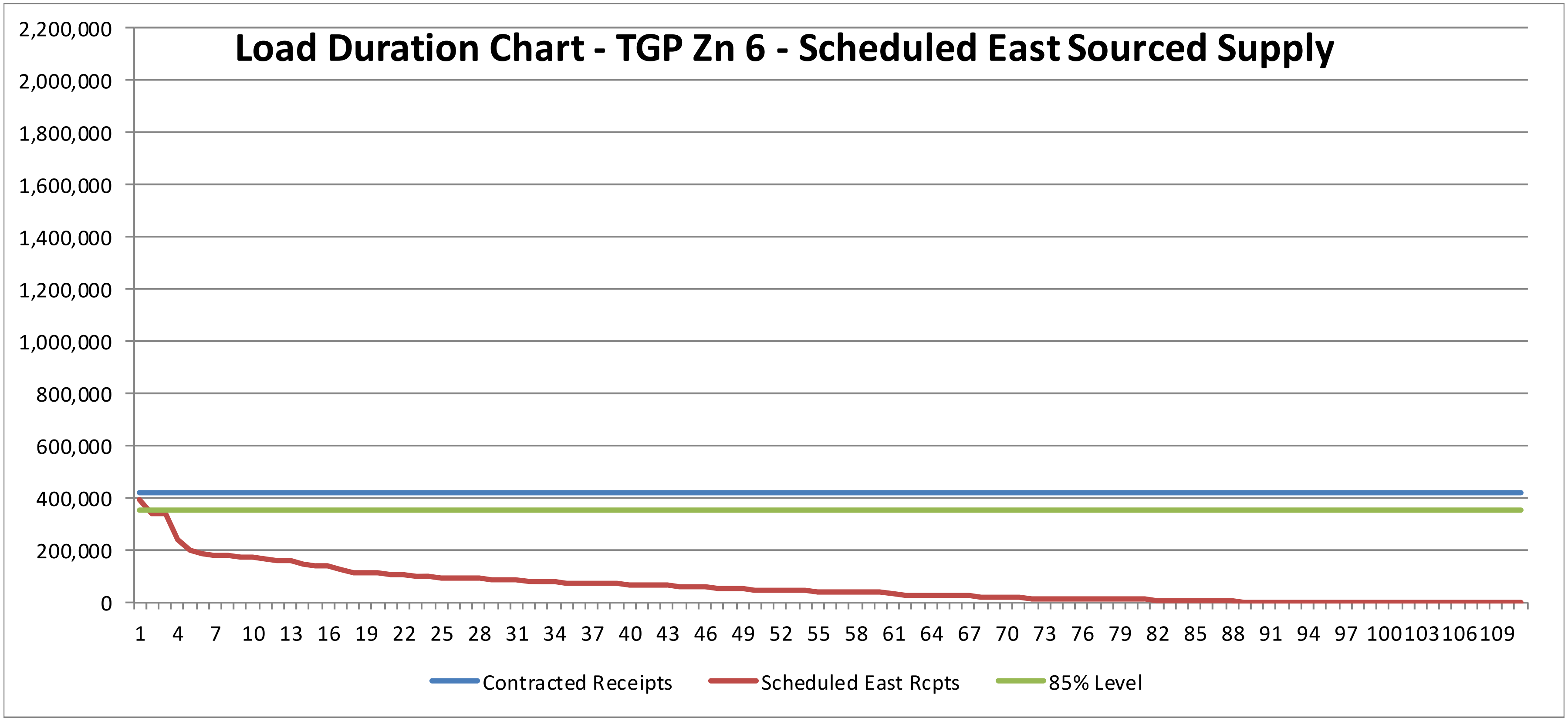

Contracted TGP Zn 6 Firm Deliveries (excl. East Receipt Contracts) Vs.
Total Scheduled Deliveries (excl. East Receipts)
2,200,000
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
01/01/2013
01/04/2013
01/07/2013
01/10/2013
01/13/2013
01/16/2013
01/19/2013
01/22/2013
01/25/2013
01/28/2013
01/31/2013
02/03/2013
02/06/2013
02/09/2013
02/12/2013
02/15/2013
02/18/2013
02/21/2013
02/24/2013
02/27/2013
03/02/2013
03/05/2013
03/08/2013
03/11/2013
03/14/2013
03/17/2013
03/20/2013
03/23/2013
03/26/2013
03/29/2013
04/01/2013
04/04/2013
04/07/2013
04/10/2013
04/13/2013
04/16/2013
04/19/2013
Contracted Deliveries Excluding East Recpt K's
Scheduled West Sourced Deliveries
85% Level of West Sourced



Contracted TGP Zn 6 Firm East Receipt Contracts Vs. Scheduled East Receipts
2,200,000
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
01/01/2013
01/04/2013
01/07/2013
01/10/2013
01/13/2013
01/16/2013
01/19/2013
01/22/2013
01/25/2013
01/28/2013
01/31/2013
02/03/2013
02/06/2013
02/09/2013
02/12/2013
02/15/2013
02/18/2013
02/21/2013
02/24/2013
02/27/2013
03/02/2013
03/05/2013
03/08/2013
03/11/2013
03/14/2013
03/17/2013
03/20/2013
03/23/2013
03/26/2013
03/29/2013
04/01/2013
04/04/2013
04/07/2013
04/10/2013
04/13/2013
04/16/2013
04/19/2013
Contracted East Receipts
Scheduled East Rcpts
85% Level


Load Duration Chart - TGP - All Zn 6 Deliveries
2,200,000
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70 73 76 79 82 85 88 91 94 97 100 103 106 109
Contracted Delivery Capacity
Scheduled Deliveries
85% Level of Contracted Deliveries


Load Duration Chart - TGP Zn 6 - Scheduled Deliveries West Sourced Supply
2,200,000
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70 73 76 79 82 85 88 91 94 97 100 103 106 109
Contracted Deliveries
Scheduled West Sourced Deliveries
85% Level


Load Duration Chart - TGP Zn 6 - Scheduled East Sourced Supply
2,200,000
2,000,000
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70 73 76 79 82 85 88 91 94 97 100 103 106 109
Contracted Receipts
Scheduled East Rcpts
85% Level