NYISO ICAP 2015/2016 Demand Curve Reset

ICAPWG
February 19th, 2016

Today's Presentation

Provide details on proposed changes to approach used to set the ICAP demand curve, including changes from Analysis Group's initial recommendations

Changes in the following highlighted areas will be discussed:

- **Periodicity**
- **Initial ICAP Demand Curve Values**
  - Estimation of Gross CONE
  - Estimation of Net EAS Revenues
  - Determination of ICAP Demand Curve Parameters
- **Annual Updates**
  - Updating of Gross CONE
  - Updating of Net EAS Revenues
  - Updating of ICAP Demand Curve Parameters

Today's Presentation (continued)

- **Provide examples of how calculations would be performed**

- **Appendices provide further details**
  - Summary of net Energy and Ancillary Services (EAS) revenue model
  - Numerical examples
  - Futures data

- **Revised recommendations reflect:**
  - Further consideration by Analysis Group of its initial recommendations
  - Feedback from Market Participants
  - Discussion with and feedback from the NYISO

Decision Criteria

- **Economic Principles**: Each recommendation should be grounded in economic theory and reflect the structure of, and incentives in, the NYISO markets
- **Accuracy**: Choices should be made with the goal of providing accurate results that capture market expectations regarding net CONE
- **Transparency**: The ICAP Demand Curve reset process (DCR) calculations and periodic updates to net CONE should be clear and transparent to Market Participants; calculation and update methods should be understandable and allow Market Participants to develop market expectations
- **Feasibility**: The DCR design and implementation should be practical and feasible from regulatory, administrative, and Market Participant perspectives
- **Historical Precedence and Performance**: DCR design decisions should – where possible and relevant – be informed by quantitative analysis based on historical data, and draw from lessons learned in the NYISO, ISO-NE and PJM wholesale capacity markets

Summary of Proposed DCR Changes

- **DCR Period: 4 years (currently, 3 years)**
- **Net EAS revenues**
  - Forecast net EAS revenues using three-year average of historical net revenues (with no econometric adjustments)
  - Adjust historical revenues to reflect market conditions at the tariff-specified level of excess (i.e., minimum installed Capacity Requirement, plus MW rating of peaking unit) through GE MAPS based scaling factors ("level of excess" adjustment)
- **Annual updates**
  - Net EAS revenues: Update annually based on updated historical net EAS revenues (new LBMPs and costs), applying fixed "level of excess" scaling factors
  - Gross CONE: Adjust based on single statewide composite escalation factor, using finalized data at the time of reset/update, sourced from publicly-available indices (change from pre-set, fixed escalation factor)
  - Calculation of Reference Point Prices: Include annual updates to the winter summer ratio (WSR) to reflect changes in system conditions

Modifications and Amendments from initial Analysis Group recommendations

- No futures adjustment in initial DCR or subsequent annual updates
- Level of excess scaling factors fixed for the duration of the DCR period
- Include annual updates to the WSR for the purpose of calculating reference points

Action Items for March BIC Vote

- **The NYISO is seeking a vote at the March BIC meeting for either:**
  - Four year periodicity, with annual updates

    Analysis Group Proposal (see previous slide)

  - Four year periodicity, without annual updates
- **March ICAPWG presentation will include preliminary recommendations on the following topics:**
  - Level of excess adjustment (additional details and methodology)
  - Financing Assumptions, including after tax weighted average cost of capital, property taxes, and amortization
  - ICAP Demand Curve shape and slope

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Proposal: DCR Period

- **Switch from current three-year period between resets to a four-year period**
  - Five or six years: Deemed not prudent
    - Forecast error increases with time
    - Fewer opportunities to incorporate stakeholder feedback
    - Higher risk that peaking unit technology and forecast elements deviate from actuals
  - Three years: Status quo
    - Accepted and understood by Market Participants
    - Frequency of resets reduces market stability, particularly if/when peaking unit technology changes
  - Four years: Recommended
    - May increase market certainty/stability vs three year reset, while reducing administrative burden for NYISO and Market Participants
    - Does not meaningfully increase risk that peaking unit technology will change between DCRs, compared to 3 years
- **Interaction with other recommendations:**
    - Move to longer DCR period increases the value of adopting a method that includes annual updates to gross CONE and net EAS revenues
      - Annual updates must be sufficiently transparent to promote and ensure market stability

Additional detail on annual updates are provided on the following slides and in greater detail starting on slide 16.

Demand Curve Calculations Over the DCR Period

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Capability Year 1 (2017/18)

Assessment of peaking unit technology:
- Gross CONE
- Net EAS revenues
- ICAP Demand Curve Values for First Capability Year

Timing:
- Data from 3-year period ending **April 30, 2016**
- Parameters in **Nov. 2016**

Capability Year 2 (2018/19)

Annual Updates
- Gross CONE inflation adjustment
- Net EAS revenues
- Winter Summer ratio
- ICAP Demand Curve Values for Second Capability Year

Timing:
- Data from 3-year period ending **Sept. 30, 2017**
- Parameters in **Dec. 2017**

Capability Year 3 (2019/20)

Annual Updates
- Gross CONE inflation adjustment
- Net EAS revenues
- Winter Summer ratio
- ICAP Demand Curve Values for Third Capability Year

Timing:
- Data from 3-year period ending **Sept. 30, 2018**
- Parameters in **Dec. 2018**

Capability Year 4 (2020/21)

Annual Updates
- Gross CONE inflation adjustment
- Net EAS revenues
- Winter Summer ratio
- ICAP Demand Curve Values for Fourth Capability Year

Timing:
- Data from 3-year period ending **Sept. 30, 2019**
- Parameters in **Dec. 2019**

Capability Year 5 (2021/22)

Assessment of peaking unit technology:
- Gross CONE
- Net EAS revenues
- ICAP Demand Curve Values for First Capability Year

Timing:
- Data from 3-year period ending **April 30, 2020**
- Parameters in **Nov. 2020**

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Proposal: Net EAS Revenue Estimation

- **Net EAS revenues earned by the peaking plant would be estimated as follows:**
  - Net EAS revenues estimated as the average net revenues earned by each peaking plant over a 3-year rolling historical period
  - A “level of excess” adjustment will be made to historical prices based on scaling factors developed through a GE MAPS analysis, determined as part of the DCR
  - Net EAS revenues for the 2017/18 Capability Year will be estimated using the 3-year period May 2013 to April 2016 for the initial consultant draft report
    - *Data could be updated for the initial filing*

Rationale:

- **Reduce complexity and improve transparency of net EAS revenue calculations;**
- **Enable the periodic updating of net EAS revenue values to reduce forecast uncertainty; and**
- **Increase viability of longer (i.e., 4-year) DCR period**

Proposal: Level of Excess Adjustment

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- **Retain adjustment of net EAS revenues to reflect tariff-prescribed level of excess conditions**
  - Purpose: adjust historic LBMPs to approximate net EAS revenues at system conditions based on the minimum Installed Capacity Requirement plus the capacity of the peaking plant – appropriate adjustments can improve the accuracy of results in approximating net CONE
  - Level of Excess (“LOE”) Adjustment to be estimated using GE MAPS model run(s) based on most recent CARIS database to identify “scaling factors” for net EAS revenue estimation
  - LOE Scaling factors based on ratio of (1) LBMP at tariff-prescribed excess conditions and (2) LBMP under current resource conditions
    - Scaling factors calculated by zone, by month, and by intra-month period (e.g., off-peak, on-peak, high on-peak)
  - Adjustment would be estimated through scaling factors established at the time of the DCR and would remain fixed until the next DCR

Net EAS Revenue Model Description

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Net EAS revenues model features:

- Hourly net revenues reflect the maximum of:
  - day-ahead commitment, and
  - real time dispatch, conditional on the unit's day ahead commitment – that is, unit operations in real-time may reflect a change in operating status if more profitable given day-ahead commitment
    - For example, unit may buy-out of DAM energy commitment if more profitable to not supply or to supply reserves; or, unit may supply in real-time, even if not committed day-ahead
- Hourly net revenues calculated to ensure that fixed startup fuel and costs are recovered
- Reserve revenues reflect operating capability of the peaking plant
- Peaking plant supplies full or no output (no partial unit supply)
- Dual fuel capability accounted for through the option to generate on natural gas or ULSD based only on day-ahead fuel prices

Detail and numerical examples for the net EAS model are provided in the Appendix.

Net EAS Revenue Model

$$\boldsymbol{Net\ EAS\ revenues\ = max\{0, net\ energy\ revenues, reserve\ revenues\}}$$

$$\boldsymbol{Net\ energy\ revenues = LOE_{Z,t} * LBMP_{Z,t} - HR * P(fuel) - VOM - ASC - EC - RS1}$$

$$EC_{hour\ i} = (CO_2Rate * CO_2Price) + (NOxRate * NOxPrice) + (SO_2Rate * SO_2Price)$$

LOE = "level of excess" adjustment for zone *Z* and time *t*

VOM = variable operations and maintenance costs

EC = emission costs

ASC = amortized startup cost (dynamically determined)

RS1 = rate schedule 1 charge

Data inputs include:

- Operating parameters of peaking unit: heat rate, start-up costs, variable O&M
- NYISO market prices: hourly day-ahead and real-time energy and reserve prices; average ancillary service revenues
- Input costs: daily fuel prices (natural gas and oil); periodic emission prices

Numeric Example: Net energy revenues for a single hour

$$Net\ energy\ revenue_{Z,t} = \\ = (LOE_{Z,t} * DAM\ LBMP_{Z,t}) - HR * Fuel - VOM - ASC - EC - RS1$$

For example, assuming LOE = 1:

$$Net\ energy\ revenue\ (per\ kW)_{hour\ i} \\ = \left(1.0 * \frac{\$100}{MWh}\right) - \left(\frac{10{,}000Btu}{kWh} * \frac{\$3}{MMBtu} + \frac{\$5}{MWh} + \frac{\$3}{MWh} + \frac{\$6}{MWh} + \frac{\$0.27}{MWh}\right)$$

$$= \$100 - \$44.27 = \frac{\mathbf{\$55.73}}{\boldsymbol{MWh}}$$

Proposal: Futures Adjustment

- **Based on discussions at the last ICAPWG and further review of futures data, a futures adjustment is not recommended at this time**
  - Revised recommendation reflects:
    - Potential for market manipulation
    - Concerns regarding zonal liquidity of futures market [see appendix]
    - Limited transparency into settled prices during periods of low or no trading volume
    - Potential overlap with other annual updates and adjustments

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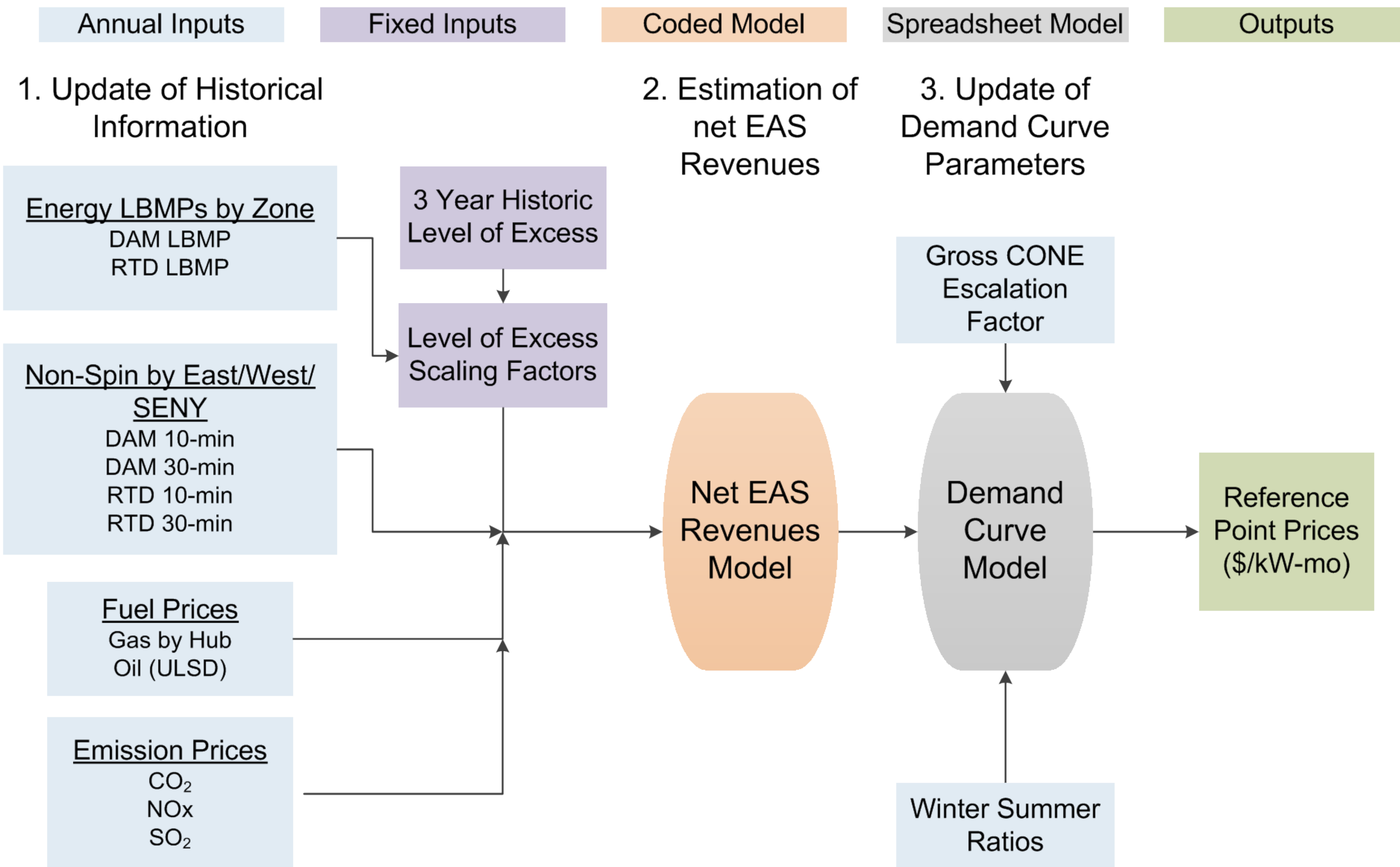
Proposal: Annual Updates

- **Update reference point prices annually, using pre-defined methodologies, based on publicly accessible market data**
  - Purpose:
    - Create a more predictable and continuous evolution of reference point prices between and within DCRs
    - Allow reference point prices to evolve with changing market conditions
    - Reduce the need for one-time forecast adjustments at the time of each reset
- **Annual Updates will require three steps:**
  1. Collect updated Historical Information
     - Energy prices
     - Fuel prices (natural gas and oil)
     - Emission allowance prices
  2. Estimate net EAS revenues using a new EAS revenue model and update gross CONE using an escalation factor
  3. Update Demand Curve parameters
     - Update Winter Summer Ratio
     - Calculate the reference point prices using a demand curve model

Flow of Annual Updates



Note: Level of Excess adjustment does not get updated annually, but is included as an input in the Net EAS Revenues model.

Annual Updates - Timeline

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Milestone	Initial Filing	Annual Updates (Prior to Capability Year)
Data Period for LBMP (3 years)	3 year period, ending April 30th*	3 year period, ending September 30th
Operations Data Finalized	May 15th*	October 15th
Filing with FERC	November	
Updates and QA/QC		October 15th – November 30th
Posting		December 15th
Strip Auction (April)	March 30th	March 30th
Spot Auction (May)	April 25th	April 25th

** Could be updated for initial filing and September recommendations.*

Approach:

- **Collect updated data for the prior 36 months (parameters in red are updated annually)**
- **Other factors remain fixed**
- **Re-run net EAS revenue model**

$$Net\ EAS\ revenues = max\{0, net\ energy\ revenues, reserve\ revenues\}$$

$$Net\ energy\ revenues = LOE_{Z,t} * LBMP_{Z,t} - HR * P(fuel) - VOM - ASC - EC - RS1$$

$$EC_{hour\ i} = (CO_2Rate * CO_2Price) + (NOxRate * NO_xPrice) + (SO_2Rate * SO_2Price)$$

LOE = "level of excess" adjustment for zone *Z* and time *t*

VOM = variable operations and maintenance costs

EC = emission costs

ASC = amortized startup cost

RS1 = rate schedule 1 charge

Indicative Data Sources for Annual Updates

Data	Regional Aggregation	Source	Unit of Analysis
Energy and Reserves			
DAM and RTD LBMP (energy)	Zonal	NYISO external	Integrated Hourly Average
DAM and RTD LBMP (reserve) 10/30 min Non-spin	Zonal	NYISO external	Integrated Hourly Average
Fuels			
Natural Gas	Daily Spot Prices	Subscription Service (example: SNL, ICE) *Note: Data will be sourced and identified for stakeholders.*	*Indicative (based on CARIS):* Zones A-E: TETCO M3 Zones F-I: Tennessee Zone 6 Zone J and K: Transco Zone 6 NY *Note: Hubs will remain fixed for duration of DCR*
Oil (ULSD)	Regional	Subscription Service	Daily
Emissions			
CO_2	Regional	RGGI Auction Clearing Price	Quarterly
NO_x	National	Subscription Service or EPA	Annual and Seasonal
SO_2	National	Subscription Service or EPA	Annual

Data Sources will be finalized during March and April ICAPWG meetings, based on input from the NYISO.

Net EAS Revenue - Data and Sources

- **The following input data, including data developed by Lummus Consultants, will remain fixed throughout the DCR:**
  - Peaking Unit Operating Characteristics:
    - Heat Rate
    - Emissions Rate
    - Summer/Winter Demonstrated Maximum Net Capability (DMNC)
    - Technology Capabilities (e.g., start time)
    - Reference Gas Hub
  - Peaking Unit Operating Costs:
    - Variable Operating and Maintenance (VOM)
    - Unit Start up Costs (per start and/or fixed start costs)
    - Natural gas transportation cost adders and taxes
    - Real-time dispatch fuel premiums
    - Rate Schedule 1

Gross CONE Escalation Factor

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Gross CONE escalated annually by single state-wide composite index, reflecting most current, finalized data available at the time of the update

Index	Weight	Source	Data Period
Wages	25%	BLS, Quarterly Census of Employment and Wages; Utility System Construction, New York Statewide, Private Owner All Establishment Sizes, Average Annual Pay (Series ID: ENU360005052371)	Annual
Materials and Components (M&C)	30%	BLS Producer Price Index, Not Seasonally Adjusted, Stage of Processing (SOP), 2200 Materials and Components for Construction (Series ID: WPUSOP2200)	Monthly (Year over Year change uses the 3-month average of finalized data, which is March/Apr/May for a September update)
Turbines and Turbine Generator Sets (TGen)	30%	BLS Producer Price Index Commodity Data, Not Seasonally Adjusted, 11 Machinery and equipment, 97 Turbines and Turbine Generator sets (Series ID: WPU1197)	
Other (GDP Deflator)	15%	Bureau of Economic Analysis, Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly (Annual average of current year Q1 and Q2 and prior year Q3 and Q4)

Initial weights provided by Lummus; final values will reflect selected peaking unit technology costs.

Gross CONE Escalation – Numerical Example

- **Composite index will reflect the weighted average of year over year changes in each index, estimated as:**

$$\boldsymbol{Composite\ Escalation_t = \sum (weight) * \left(\frac{Index_{current\ data}}{Index_{year\ prior data}} - 1\right)}$$

Value	Calculation	Construction Labor	Materials	Turbine	GDP Deflator
Year 1	[A]	92,500	227	232	104
Year 2	[B]	93,000	229	233	106
Growth Rate	([B]/[A])-1	0.54%	0.88%	0.43%	1.92%
Weights		25%	30%	30%	15%
Composite Escalation Factor for Annual Update		(0.54%*25%) + (0.88%*30%) + (0.43%*30%) + (1.92%*15%) = **0.82%**			

All values are hypothetical and illustrative.

- **Annual revenue requirement derived utilizing updated values and the demand curve model will be translated to the reference price, using the formula below (set forth in Section 5.5 of the Installed Capacity Manual)**

Consequently:

$$RP_i = \frac{ARV_i \cdot \dfrac{AssmdCap}{SDMNC}}{6 \cdot \left[1 + \dfrac{WDMNC}{SDMNC} \cdot \left(1 - \dfrac{WSR_i - 1}{ZCPR_i - 1} \right) \right]},$$

Where:

ARV_i = the Annual Reference Value for location *i*;

AssmdCap = the capacity assumed for the peaking unit when calculating Annual Reference Values;

SDMNC = the summer DMNC assumed for the peaking unit at the temperature used to establish the ICAP Demand Curve;

WDMNC = the winter DMNC assumed for the peaking unit at the temperature used to establish the ICAP Demand Curve;

Source: ICAP Manual, p. 5-7.

Proposal: Adjust the WSR

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- **Update the Winter Summer Ratio (WSR) as part of the annual update process**
  - Purpose: Changes to the WSR incorporate and reflect changes in system resource conditions

- **The methodology for calculating the value of the WSR remains under review, but will be finalized as part of the ongoing reset process**
  - Note: Reference peaking plant DMNC rating will be established during the reset and remain fixed throughout the DCR period

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- Hourly net revenues calculated to ensure that fixed startup fuel and costs are recovered
- Reserve revenues reflect operating capability of the peaking plant
- Hourly net revenues reflect the maximum of:
    - day-ahead commitment and,
    - real time dispatch, conditional on the unit's day ahead commitment – that is, unit operations in real-time may reflect a change in operating status if more profitable given day-ahead commitment
        - For example, unit may buy-out of DAM energy commitment if more profitable not to supply or to supply reserves; or, unit may supply in real-time, even if not committed day-ahead
- Peaking plant supplies full or no output (no partial unit supply)
- Dual fuel capability accounted for through the option to generate on natural gas or ULSD based only on day-ahead fuel prices

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Numeric Examples: Net EAS Revenue DAM economic logic

- Unit day ahead position and commitment reflect highest profit from supplying Energy, supplying (non-spin) reserves or not supplying (Energy or reserves)
- **Example 1:**
  - LOE = 1; DAM LBMP = $100; Cost = $45; DAM Reserves = $30

DAM Energy = ((1*$100) - $45) = $55 Energy
DAM Reserves = $30 Reserves
Unit Commits <u>DAM for Energy</u>

- **Example 2:**
  - If instead, DAM LBMP = $35; and DAM Reserves = $0

DAM Energy = ((1*$35) - $45) = $-10 Energy
DAM Reserves = $ 0 Reserves
Unit <u>Does Not Commit</u>

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Numeric Example: Level of Excess Adjustment

- **Example 2 (from before):**
  - DAM LBMP = $35; Cost = $45; and DAM Reserves = $0
  - If LOE = 1:

DAM Energy = ((1*$35) - $45) = $ -10 Energy
DAM Reserves = $ 0 Reserves
Unit Does Not Commit

  - If LOE = 1.4 *(hypothetical value)*

DAM Energy = ((1.4*$35) - $45) = $ 4 Energy
DAM Reserves = $ 0 Reserves
Unit Does Commit DAM Energy

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Numeric Examples: Net EAS Revenue RTD logic

- **Example 2 (continued): Unit did not commit DAM for Energy or reserves:**
  - Unit real time position and commitment reflect highest profit from supplying Energy, supplying reserves or not supplying (Energy or reserves)
  - **Example 2A:** Unit commits RTD for Energy
    - RTD LBMP = $100; Cost *w/ Fuel Premium* = $50; RTD Reserves = $30

RTD Energy = ((1*$100) - $50) = $50 Energy
RTD Reserves = $30 Reserves
<u>Unit Commits RTD for Energy</u>

  - **Example 2B:** Unit commits RTD for reserves
    - RTD LBMP = $50; Cost *w/ Fuel Premium* = $50; RTD Reserves = $30

RTD Energy = ((1*$50) - $50) = $ 0 Energy
RTD Reserves = $30 Reserves
<u>Unit Commits RTD for Reserves</u>

Numeric Examples: Net EAS Revenue RTD logic

- **Example 1: Unit committed DAM for Energy:**
  - **Example 1A:** Unit buys out of DAM Energy commitment
    - Buy-out of DAM when (RTD Price + Fuel Loss) < Costs
    - DAM LBMP = $60; RTD LBMP = $15; Costs = $45; Fuel Loss = $20

Without DAM Buyout: $60 - $45 = $15
With DAM Buyout: $60 - $15 - $20 = $25
<u>Unit Buys Out of DAM Energy Commitment</u>

  - **Example 1B:** Unit buys out of DAM Energy commitment and provides reserves in real-time
    - Buy-out of DAM when (RTD Price + Fuel Loss) < (Costs - Reserves)
    - DAM LBMP = $60; RTD LBMP = $15; Costs = $45; Fuel Loss = $20 RTD Reserves = $30

Without DAM Buyout: $60 - $45 = $15
With Buyout and Reserves: $60 - $15 - $20 + $30 = $55
<u>Unit Buys out of DAM Energy Commitment and Provides Reserves</u>

Numeric Examples: Net EAS Revenue RTD logic

- **Example 3: If Unit committed DAM for reserves:**
  - **Example 3A:** Unit buys out of reserves commitment
    - Buy-out of DAM reserve commitment when real-time price is $0
    - DAM Reserves: $30; RTD Reserves: $0

Without DAM Buyout: $30
With DAM Buyout: $30 - $0 = $30
<u>Unit Buys Out of DAM Reserve Commitment</u>

  - **Example 3B:** Unit buys out of DAM reserves commitment and provides Energy
    - Buy-out and provide Energy when (LBMP - Cost) > (Reserve - Buyout)
    - DAM Reserves: $30; RTD Reserves: $0; RTD LBMP = $100; Costs with Fuel Premium = $50

Without DAM Buyout: $30
With Buyout and RTD: ($30 - $0) + ($100 - $50) = $80
<u>Unit Buys Out of DAM Reserve Commitment and Provides Energy</u>

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Numeric Example: Annual Update Year (example, 2018/19):

- **Annual updates will sum hourly profits, estimated using the logic presented in the previous numerical examples**

$$Net\ EAS\ Revenue_t = \frac{1}{3}\sum_{i=-3}^{-1} Net\ EAS\ Revenue_{Oct_{i\_1} to\ Sept i}$$

$$Net\ EAS\ Revenue_{2018/19} = \left(\frac{1}{3}\right)\left[Net\ EAS\ Revenue_{Oct14-Sep15} + Net\ EAS\ Revenue_{Oct15-Sep16} + Net\ EAS\ Revenue_{Oct16-Sep17}\right]$$

$$Net\ EAS\ Revenue_{2018/19} = \left(\frac{1}{3}\right) * [\$19 + \$21 + \$23] = \$21.00\ per\ kW - year$$

Where net EAS revenue reflects the sum of all hours using the detail examples and expressed in $/kW-yr.

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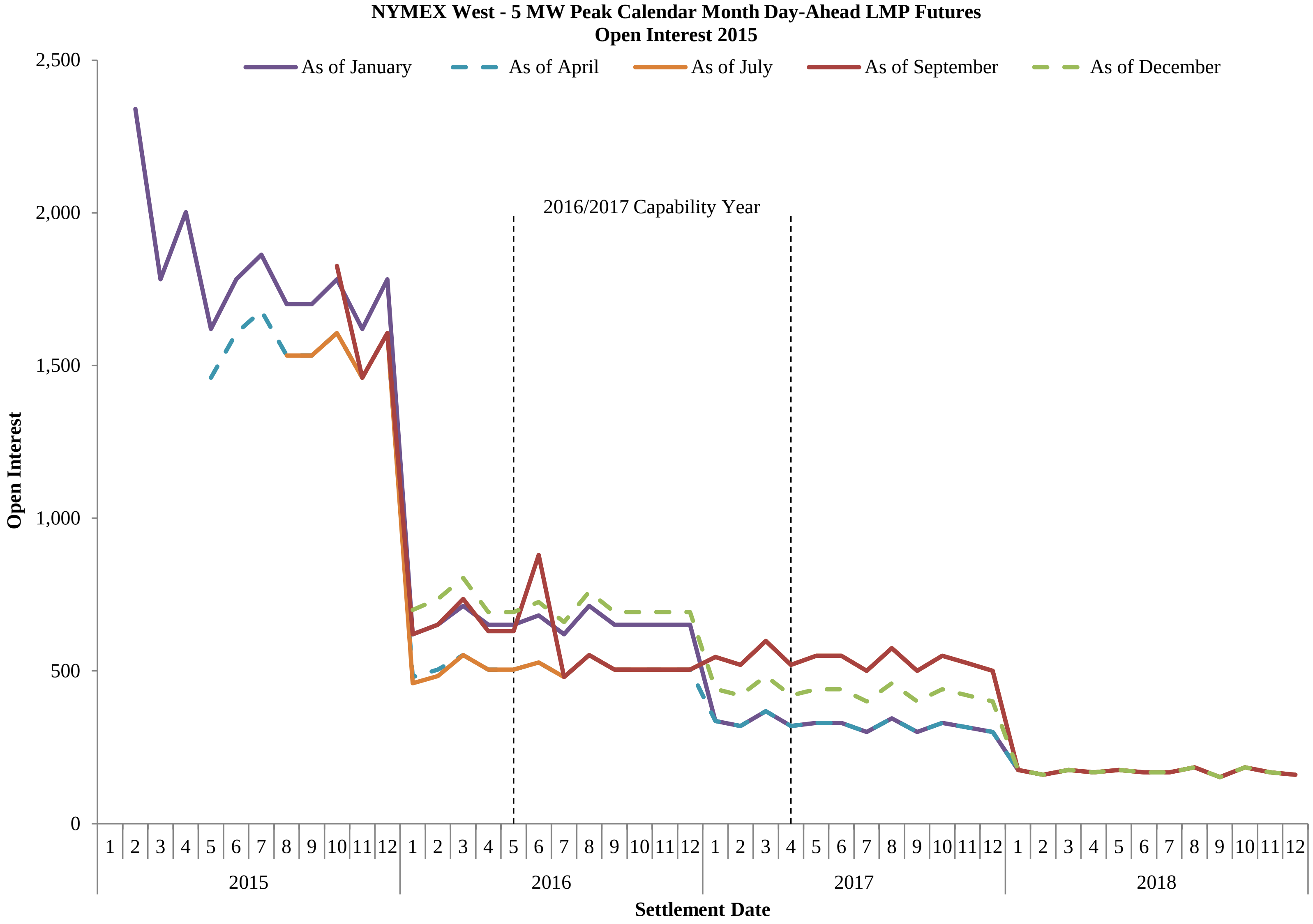
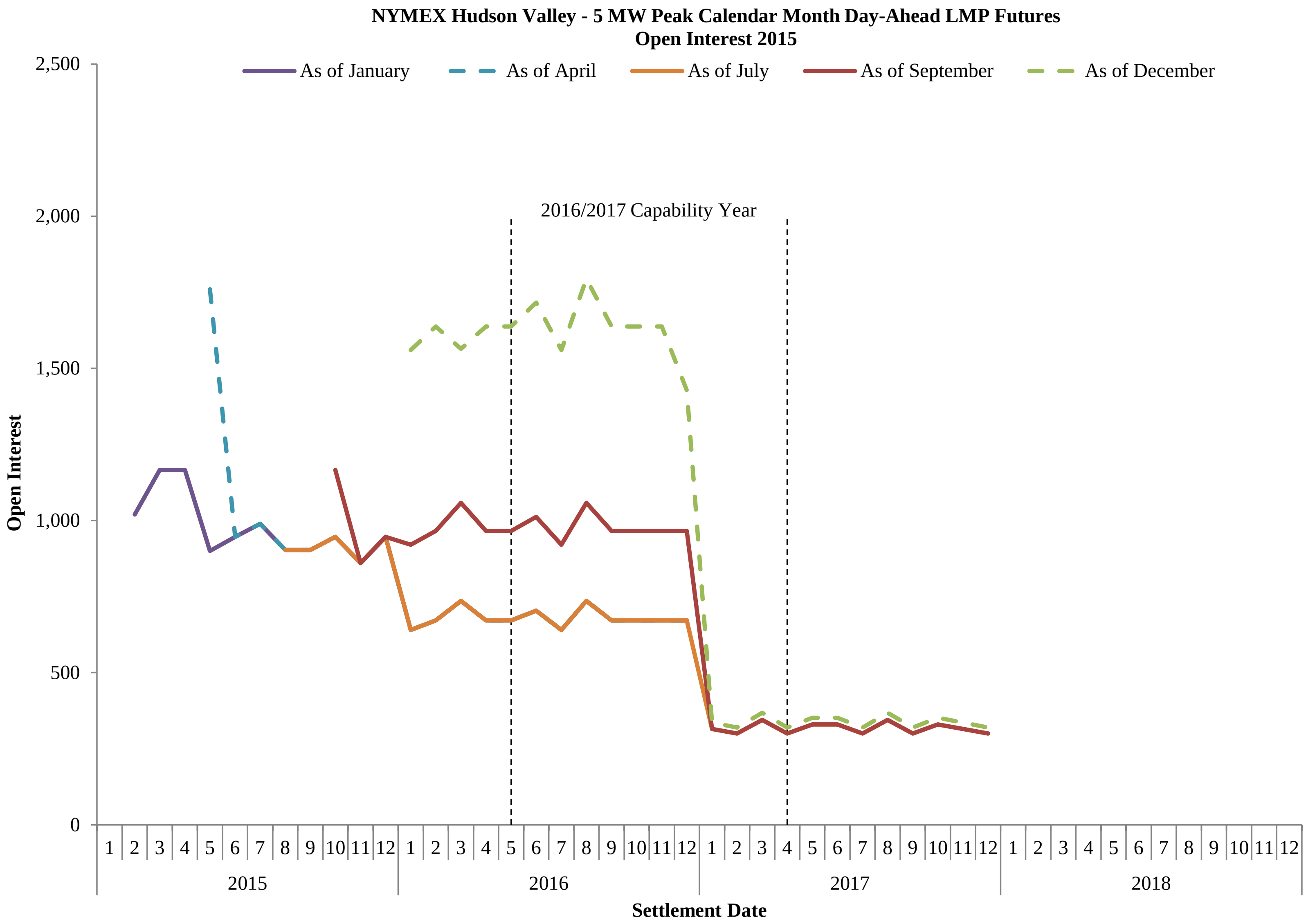
NYMEX Open Interest – Zone A



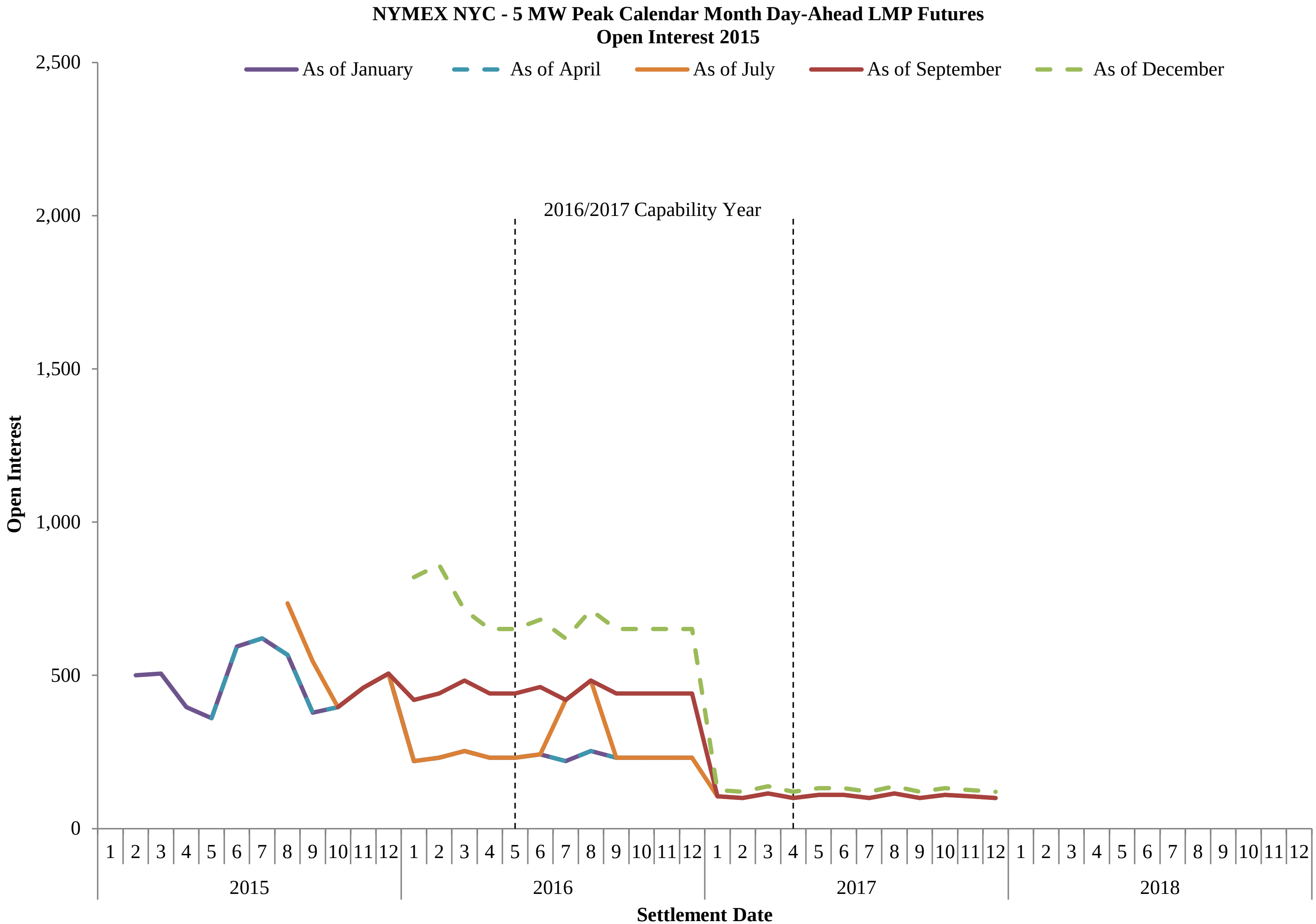
Source: SNL Financial

NYMEX Open Interest – Zone G



Source: SNL Financial

NYMEX Open Interest – Zone J



Source: SNL Financial

Gross CONE Composite Index

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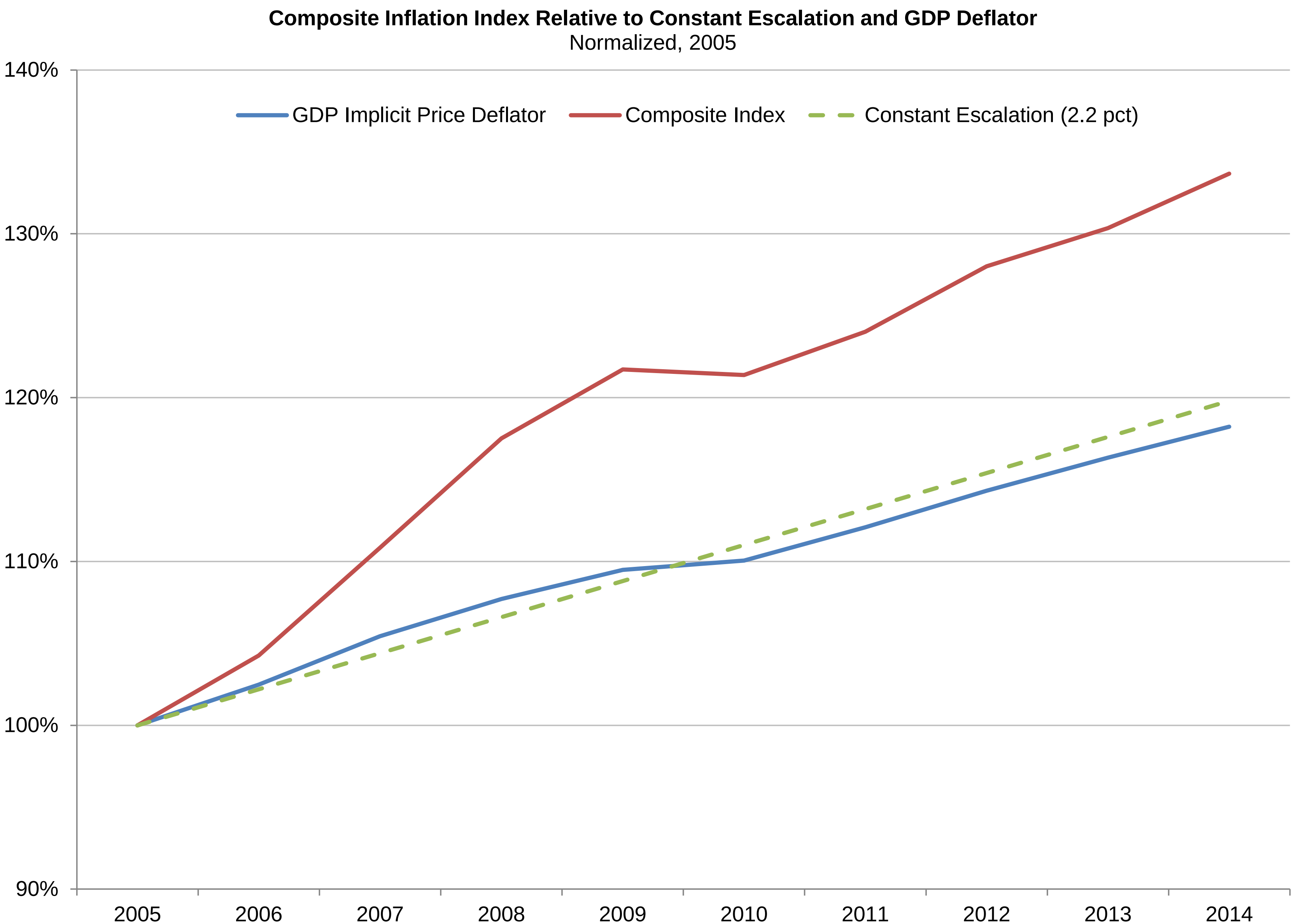
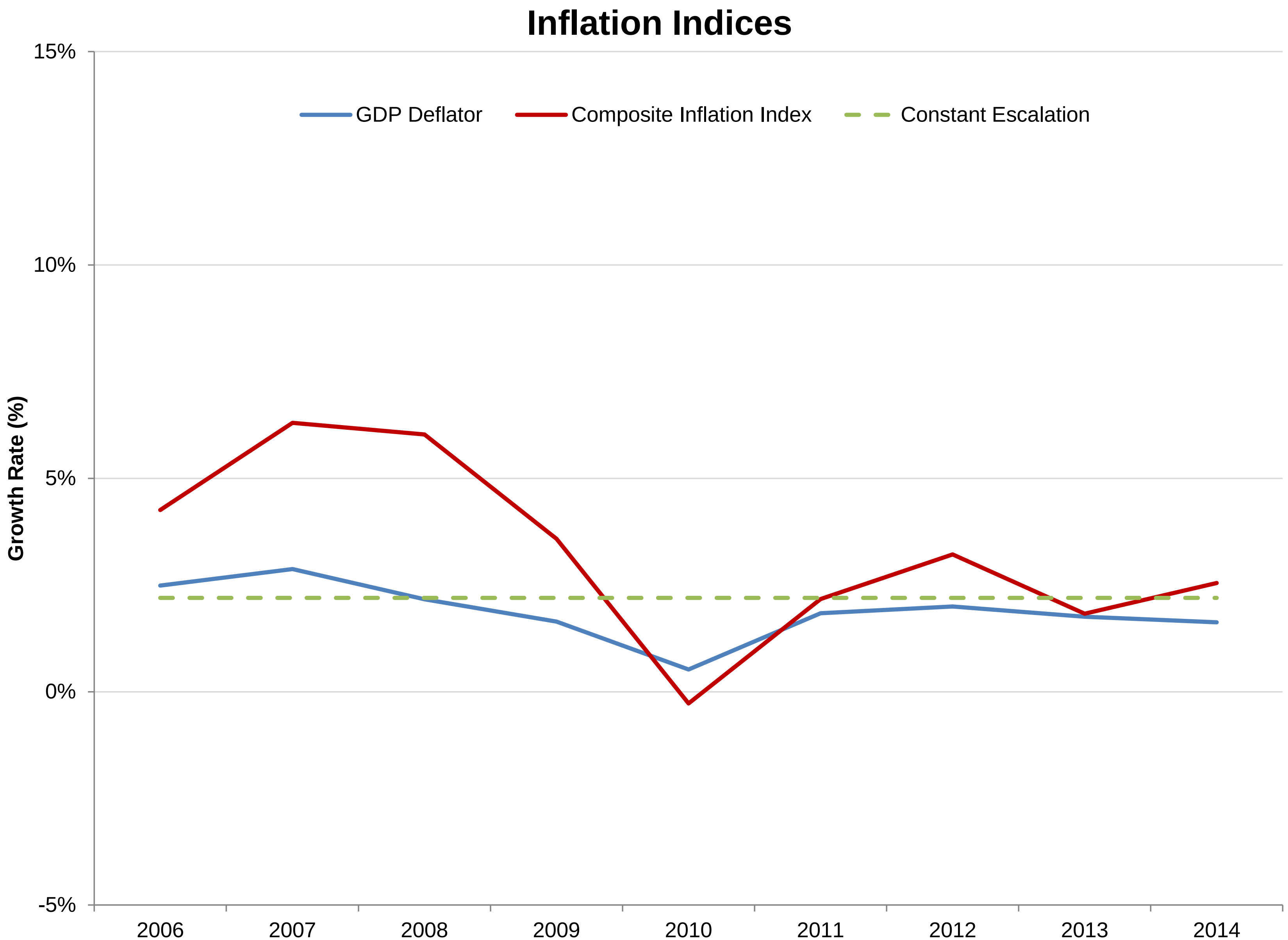


Gross Cone Composite Index – Annual Change



Sensitivity of Reference Point Price to WSR

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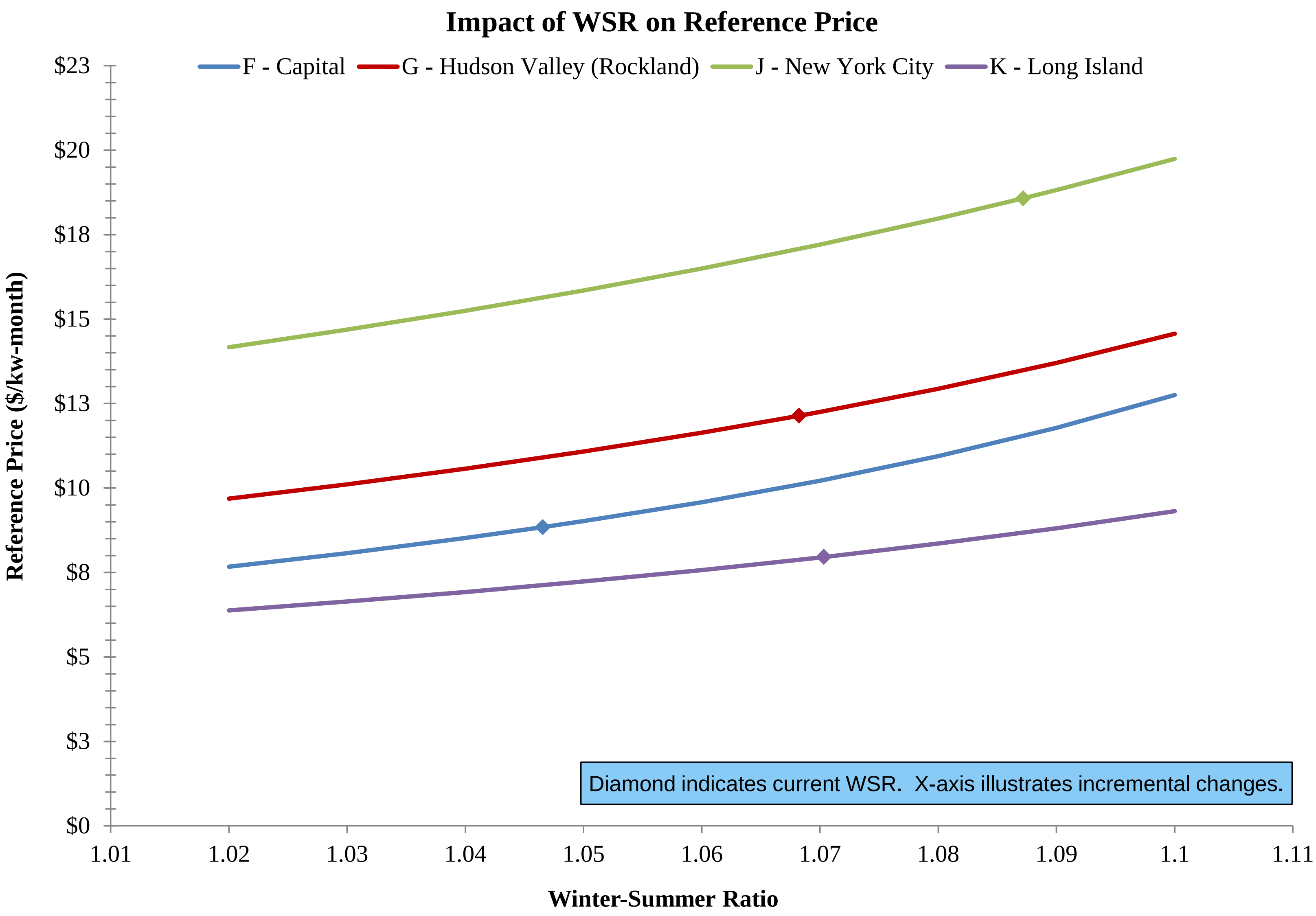

Note: Diamond indicates WSR base case.