McCormick

Northwestern Engineering

Investment Effects of Pricing Schemes for Wholesale Electricity Markets

Jacob Mays

Joint work with Richard O'Neill (FERC) and David Morton (Northwestern)

June 27, 2018

Views expressed are not necessarily those of the Commission

Motivation

Principle of competitive markets:

Transparent & Complete Price Signals → **Welfare-Maximizing Investment Outcomes**

- **In wholesale electricity markets, producing complete price signals is a challenge**
- **Low prices could be a healthy market signal or an unhealthy consequence of price formation**

Our question: what effects do competing price formation methods have on investment?

Contributions

Experimental design:

- **Provide evidence that revenue from locational marginal prices without side payments supports the optimal long-term capacity mix**

- **Help understand the implications various pricing methods have for the long-term capacity mix**

Outline

- Price formation
- Two generator model
  - Optimality
  - Pricing
- Larger system
  - Optimality
  - Pricing
- Discussion

Non-convex example

Imagine we have a system served by two generators:

	Generator C	Generator N
Startup cost ($)	0	1,000
Energy cost ($/MWh)	0	25
Minimum operating level (MW)	0	20
Maximum operating level (MW)	60	40

- **When deciding how to serve load, a key decision is whether to incur the startup cost of generator N**

Non-convex example

What happens if demand is 70 MW?

	Gen C	Gen N
Startup	$0	$1,000
Energy	$0/MWh	$25/MWh
Min level	0 MW	20 MW
Max level	60 MW	40 MW

- **Dispatch generator N to its minimum operating level**
- **Dispatch generator C to 50 MW**
- **Generator C is still marginal**
- **LMP is still $0/MWh**

> **Generator N has cost of $1,500 and revenue of $0, so would rather not turn on**

Uplift

- **Given the posted prices, market participants have an incentive to deviate from the optimal dispatch:**

Maximal profit – **Profit as dispatched** = **Lost opportunity cost**

- **A special type of lost opportunity cost occurs when the profit as dispatched is negative:**

$$-\min\left\{0, \text{Profit as dispatched}\right\} = \text{Make-whole payment}$$

Price formation

Several proposals have been advanced to help resolve these incentive compatibility problems

Relaxed LMP	Extended LMP	Average Incremental Cost
• Allows energy cost of generators at minimum operating level to set price	• Amortizes fixed costs over maximum operating level • Allows fixed and energy cost to set price	• Amortizes fixed costs over actual operating level • Guarantees non-negative profit for all generators
$25/MWh	**$50/MWh**	**$75/MWh**

Convex hull pricing

- **Price formation proposals can alleviate but not eliminate incentive compatibility issues**

Method	Price ($/MWh)	Make-whole payments	Lost opportunity costs
Marginal (LMP)	0	$1,500	$1,500
Relaxed (RLMP)	25	$1,000	$1,250
Extended (ELMP)	50	$500	$1,000
Average (AIC)	75	$0	$1,750

- **Convex hull pricing (CHP) has the property that it minimizes a version of lost opportunity costs**
- **In this talk, will distinguish between CHP and ELMP by allowing offline units to set prices only in CHP**

Outline

- Price formation
- Two generator model
  - Optimality
  - Pricing
- Larger system
  - Optimality
  - Pricing
- Discussion

Capacity expansion

Goal is to find the collection of investments that maximizes the value of operating the system minus the upfront cost

Investment cost linear in the installed capacity of each generation type

$$\max_{\boldsymbol{x}} \quad -\sum_{g\in G} c_g^{inv} x_g + \mathrm{E}[H(x;D)]$$

$$s.t. \quad x \geq 0$$

Operating cost is a function of the collection of investments that are made and is subject to uncertain demand

Example parameters

- **Allow the generator parameters from before to scale with the amount of installed capacity:**

	Generator C (1)	Generator N (2)
Investment cost ($/MW)	80	50
Startup cost ($)	0	$50\alpha x_2$
Energy cost ($/MWh)	0	$50(1-\alpha)$
Minimum operating level (MW)	0	τx_2
Maximum operating level (MW)	x_1	x_2

- **Parameters α and τ control the amount of non-convexity in the problem**
- **Generator N costs $50/MWh to operate at full power regardless of α or installed capacity**

Unit commitment

Market surplus for a given capacity mix and demand level can be calculated as

$$H(x;D) = \max_{u,p,d} \quad bd - c_1^{en} p_1 - c_2^{su} u_2 - c_2^{en} p_2$$

$$s.t. \quad p_1 + p_2 = d$$

$$d \leq D$$

$$0 \leq p_1 \leq x_1$$

$$\tau x_2 u_2 \leq p_2 \leq x_2 u_2$$

$$u_2 \in \{0,1\}$$

Value of load

Cost to serve load

Power balance

Max demand

Technical feasibility

Parameter governing minimum operating level of generator N

Commitment decision

Unit commitment solution

We can easily solve the unit commitment problem for any level of demand in terms of the first-stage variables:

Demand Range	p_1^*	p_2^*
$0 \leq D < x_1$	D	0
$x_1 \leq D < \max\{x_1 + \epsilon x_2, \tau x_2\}$	x_1	0
$\max\{x_1 + \epsilon x_1, \tau x_2\} \leq D < x_1 + \tau x_2$	$D - \tau x_2$	τx_2
$x_1 + \tau x_2 \leq D < x_1 + x_2$	x_1	$D - x_1$
$x_1 + x_2 \leq D$	x_1	x_2

- **Allows computation of second stage value as a function of installed capacity**

Note: ϵ chosen such that ϵx_2 represents the residual demand required to justify incurring startup cost of generator N

Quadratic formulation

Choosing $D \sim U(0,1)$, rewrite the capacity expansion problem in terms of only the first stage variables:

$$\max_{x} \quad -80x_1 - 50x_2$$

Investment Cost

$$+b\left[(x_1)\, x_1/2 + (\epsilon x_2)x_1 + (x_2 - \epsilon x_2)(2x_1 + \epsilon x_2 + x_2)/2 + (1 - x_1 - x_2)(x_1 + x_2)\right]$$

Value of served load

$$-50\alpha x_2(1 - (x_1 + \epsilon x_2))$$

Startup Cost

$$-50(1-\alpha)[(\tau x_2 - \epsilon x_2)(\tau x_2) + (x_2 - \tau x_2)(x_2 + \tau x_2)/2 + (1 - x_1 - x_2)x_2]$$

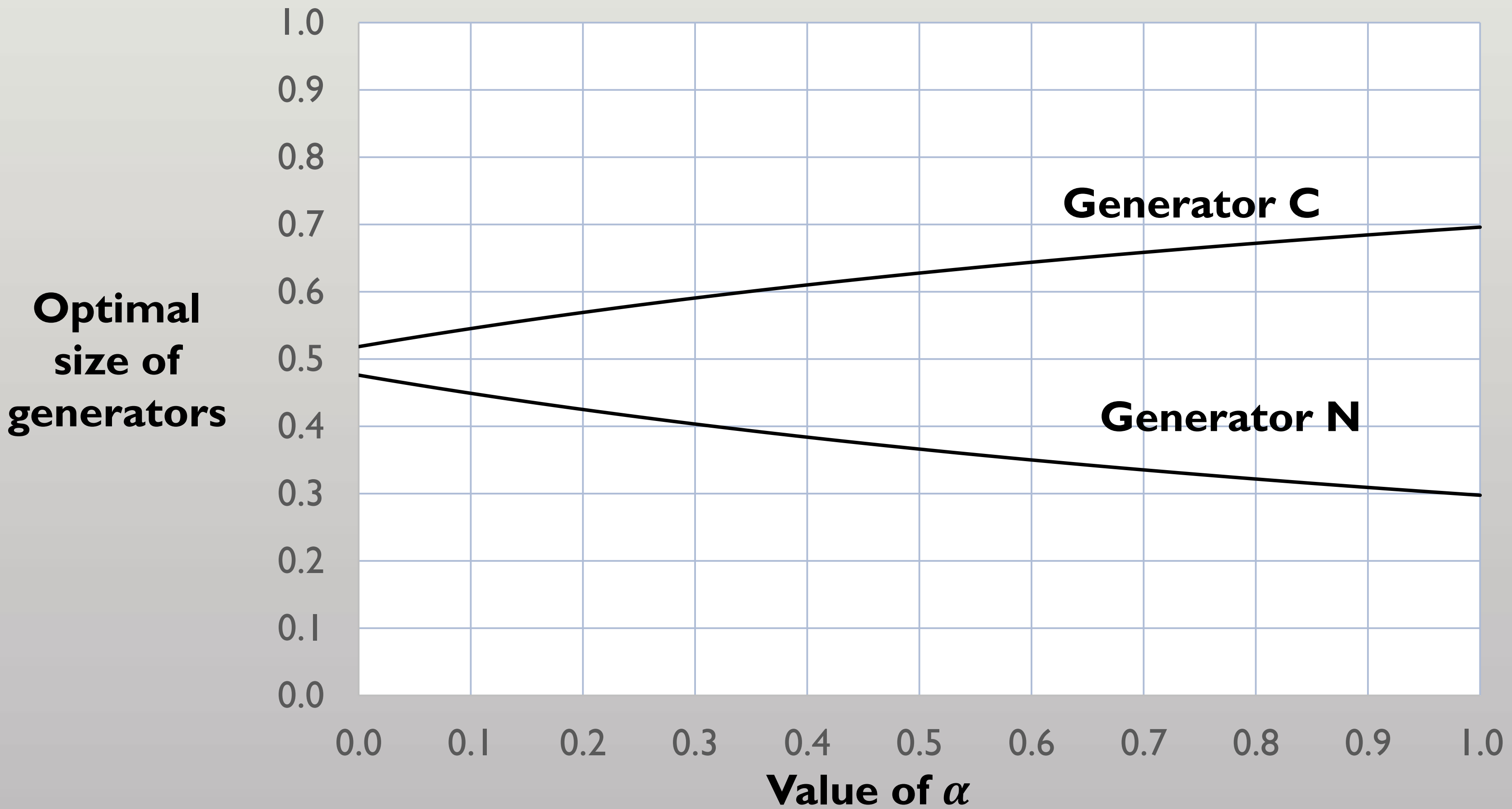
Energy cost

$$s.t. \qquad x_1, x_2 \geq 0$$

McCormick
Northwestern Engineering

Optimal capacity mix

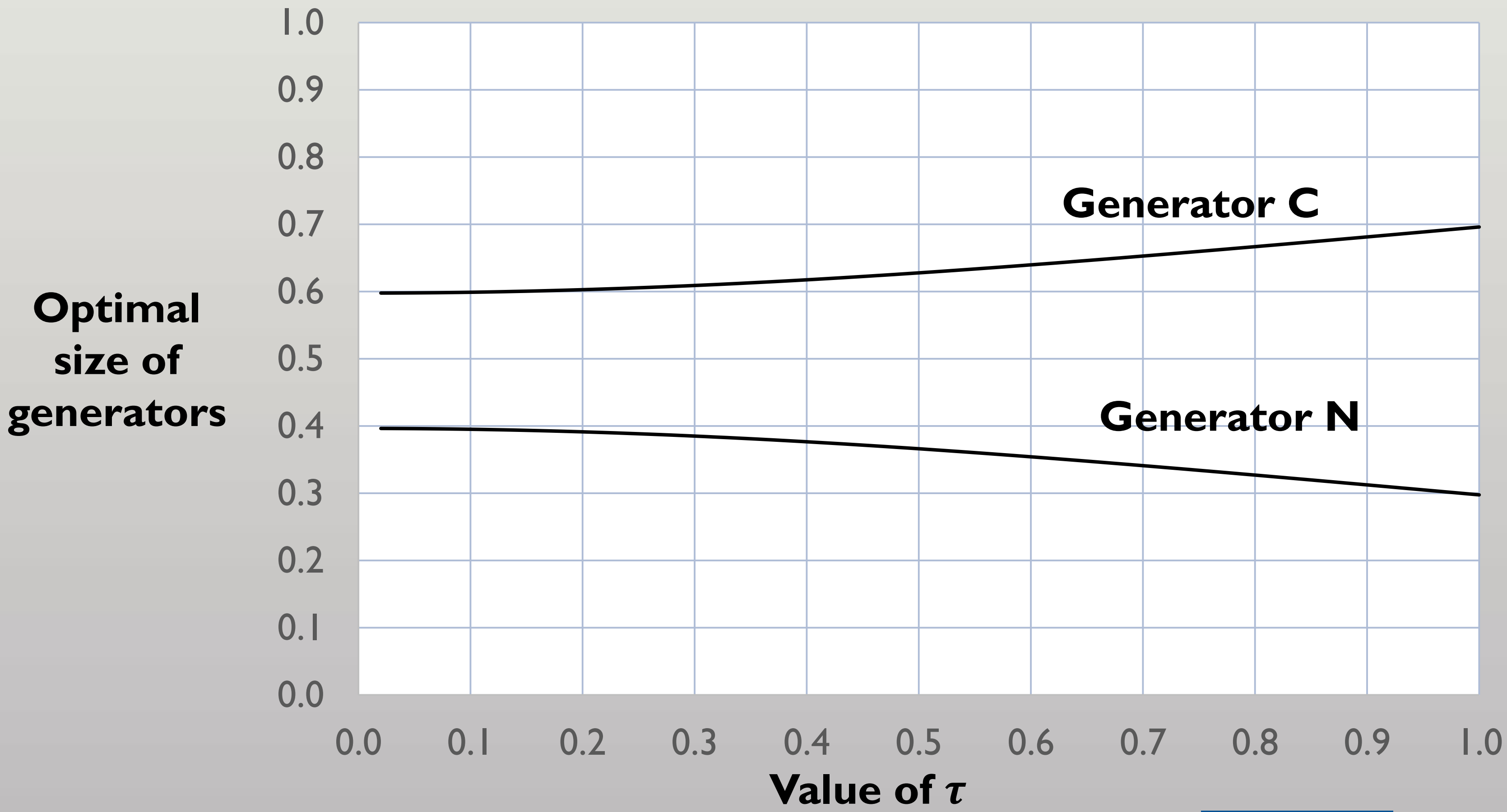
The optimal size of generator N falls as non-convex parameters become more salient



Note: Assumes $\tau = 0.5, b = 10,000$

Optimal capacity mix

The optimal size of generator N falls as non-convex parameters become more salient



Note: Assumes $\alpha = 0.5, b = 10,000$

McCormick Northwestern Engineering

Outline

- Price formation
- **Two generator model**
  - Optimality
  - **Pricing**
- Larger system
  - Optimality
  - Pricing
- Discussion

McCormick Northwestern Engineering

Pricing evaluation

- **Want to test the performance of pricing schemes introduced before**
  - **LMP, RLMP, ELMP, AIC, CHP**
- **We also consider three strategies for uplift**
  - **No uplift payments**
  - **Make-whole payments (MWP)**
  - **Payments for all lost opportunity costs (LOC)**
- **Assume $\alpha = \tau = 0.5$ and $b = 10,000$**
- **With chosen parameters, system optimum is at $x_1^* = 0.6278$ and $x_2^* = 0.3661$, for a total capacity of $x_1^* + x_2^* = 0.9938$**

McCormick
Northwestern Engineering

Pricing run results

In energy-only markets, a substantial portion of revenue is earned when demand sets the price

Demand Range	CHP	LMP	RLMP	ELMP	AIC
1	0	0	0	0	0
2	50	10,000	10,000	10,000	10,000
3	50	0	25	50	75
4	50	25	25	50	$25(1+\frac{x_2}{d^{max}-x_1})$
5	10,000	10,000	10,000	10,000	10,000

- **Most expensive generator can only earn a profit when demand side sets the price**

Profitability at system optimum

- **Compute net margin[1] under each settlement scheme at the system optimum**
- **In competitive markets, expect zero profits in equilibrium**

Net margin with no uplift payments

	LMP
Generator C	0%
Generator N	0%

System optimum has zero profits under LMP with no uplift payments

1: For consistency, all net margin calculations use revenue under LMP with no uplift

McCormick
Northwestern Engineering

Profitability at system optimum

Use of uplift payments disproportionately benefits the non-convex unit

Net margin under LMP

	No Uplift	w/ MWP	w/ LOC
Generator C	0%	0%	0%
Generator N	0%	17%	38%

- **Generator C cannot benefit from make-whole payments and has small lost opportunity costs**

Profitability at system optimum

Allowing the higher-cost unit to set prices disproportionately benefits the lower-cost unit

Net margin with make-whole payments

	LMP	RLMP	ELMP	AIC
Generator C	0%	5%	15%	37%
Generator N	17%	17%	17%	17%

- **When the more expensive generator N sets the price, generator C is typically operating at max**

Profitability at system optimum

Convex hull pricing reduces total compensation below level required to support optimum

Net margin with no uplift payments

	LMP	CHP
Generator C	0%	-2%
Generator N	0%	12%

- **Allowing generator N to set the price while offline can reduce price relative to LMP**

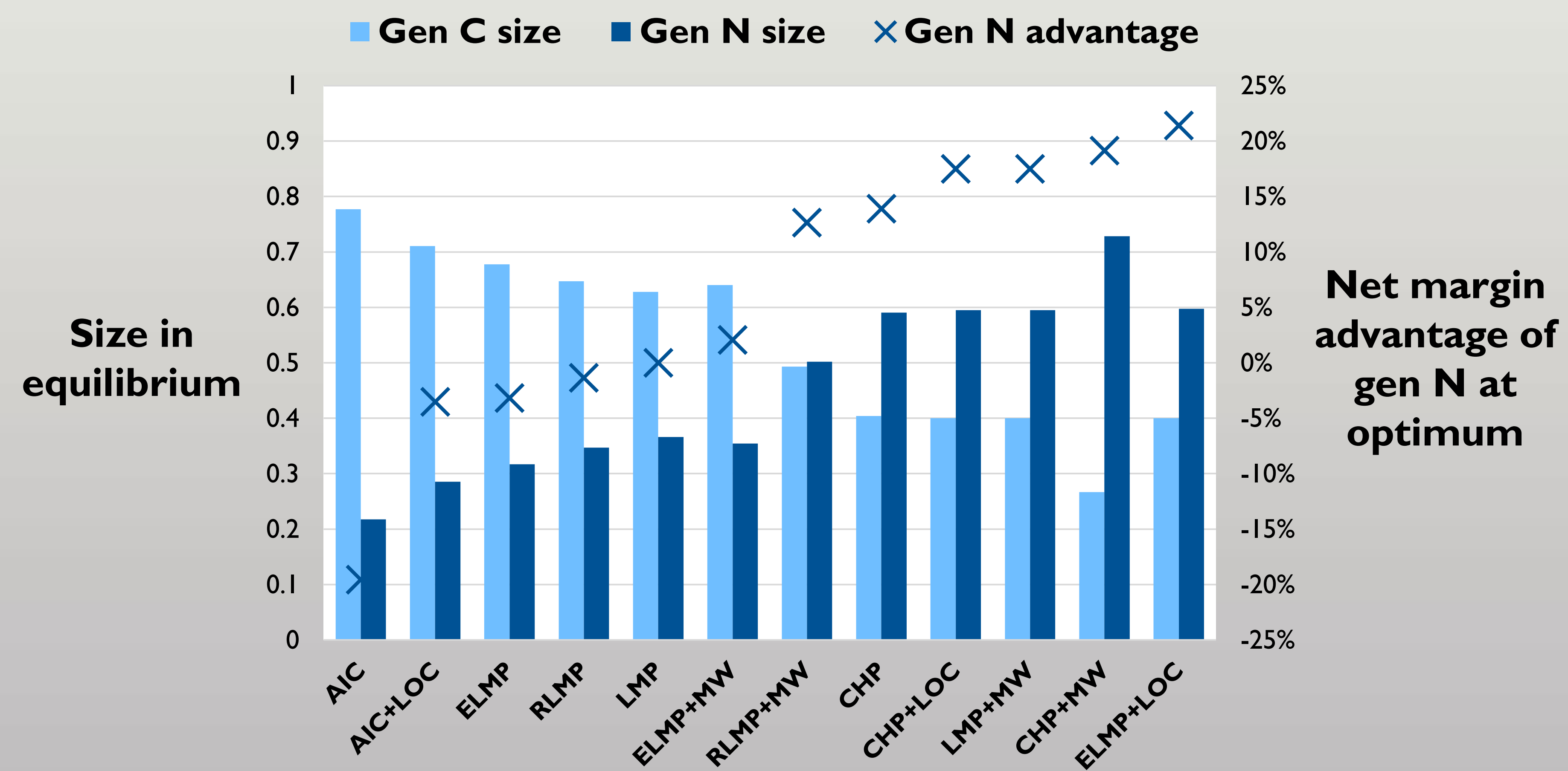
Equilibrium capacity mix

- **Before, computed optimal dispatch as function of installed capacity**
- **Can also compute profitability as a function of installed capacity**
- **Setting profitability of each generator to zero yields a system of two non-linear equations**

Solve system of equations to find equilibrium capacity mix for each settlement strategy

Equilibrium capacity mix

Profitability at system optimum correlates with capacity at equilibrium



Note: Chart excludes settlement strategies for which no equilibrium solution exists.

McCormick
Northwestern Engineering

Outline

- Price formation
- Two generator model
  - Optimality
  - Pricing
- Larger system
  - Optimality
  - Pricing
- Discussion

Larger system

- We consider six generation types:

Nuclear	Coal	Combined Cycle Gas
Wind	Solar	Open Cycle Gas

- Cost and technical characteristics tuned to result in diverse mix at system optimum
- Ten percent of demand considered responsive
  - Helps stabilize profitability estimates
  - Similar results could be obtained with a well-designed operating reserves demand curve (ORDC)

Capacity expansion

Several changes are made to the capacity expansion and unit commitment problems

$$\max_{\boldsymbol{x},\boldsymbol{z}} \quad -\sum_{g} c_{inv}^{g} x_g + \sum_{s} w_s q_s' z_s$$

$$s.t. \quad u_t^g, v_t^g, p_t^g \leq x_g \quad \forall g, t$$

$$x \in \{0,1\}^n, z \in Z$$

Uncertainty includes 24 week-long scenarios for demand, wind output, and solar output

Generation expansion decisions are binary

z incorporates all unit commitment decisions

Unit commitment

In each scenario, operations maximize value of load served minus the three-part cost of generation

$$\max_{u,v,p,d} \sum_{l} \sum_{t} w_t^l d_t^l - \sum_{g} \sum_{t} (c_{nl}^g u_t^g + c_{su}^g v_t^g + c_{en}^g p_t^g)$$

$$s.t. \quad \sum_{g} p_t^g = \sum_{l} d_t^l \quad \forall t$$

Power balance

$$\sum_{g} p_t^{g,a} \geq r_t^a \quad \forall a, t$$

Supply of reserves

$$(u^g, v^g, p^g) \in \mathcal{F}^g \quad \forall g$$

Technical feasibility

$$u_t^g, v_t^g, p_t^g \leq x_g \quad \forall g, t$$

Link to capacity investment decision

First-stage contour

A large number of capacity mixes lead to similar overall welfare

Example near-optimal solutions (MW installed capacity)

Technology	Solution 1	Solution 2
Nuclear	4000	4500
Coal	1500	3500
CC Gas	16000	12800
OC Gas	7200	7400
Wind	10400	9200
Solar	6400	7000

- **Should not rely on pricing results from a single solution given large number within optimality gap**

Outline

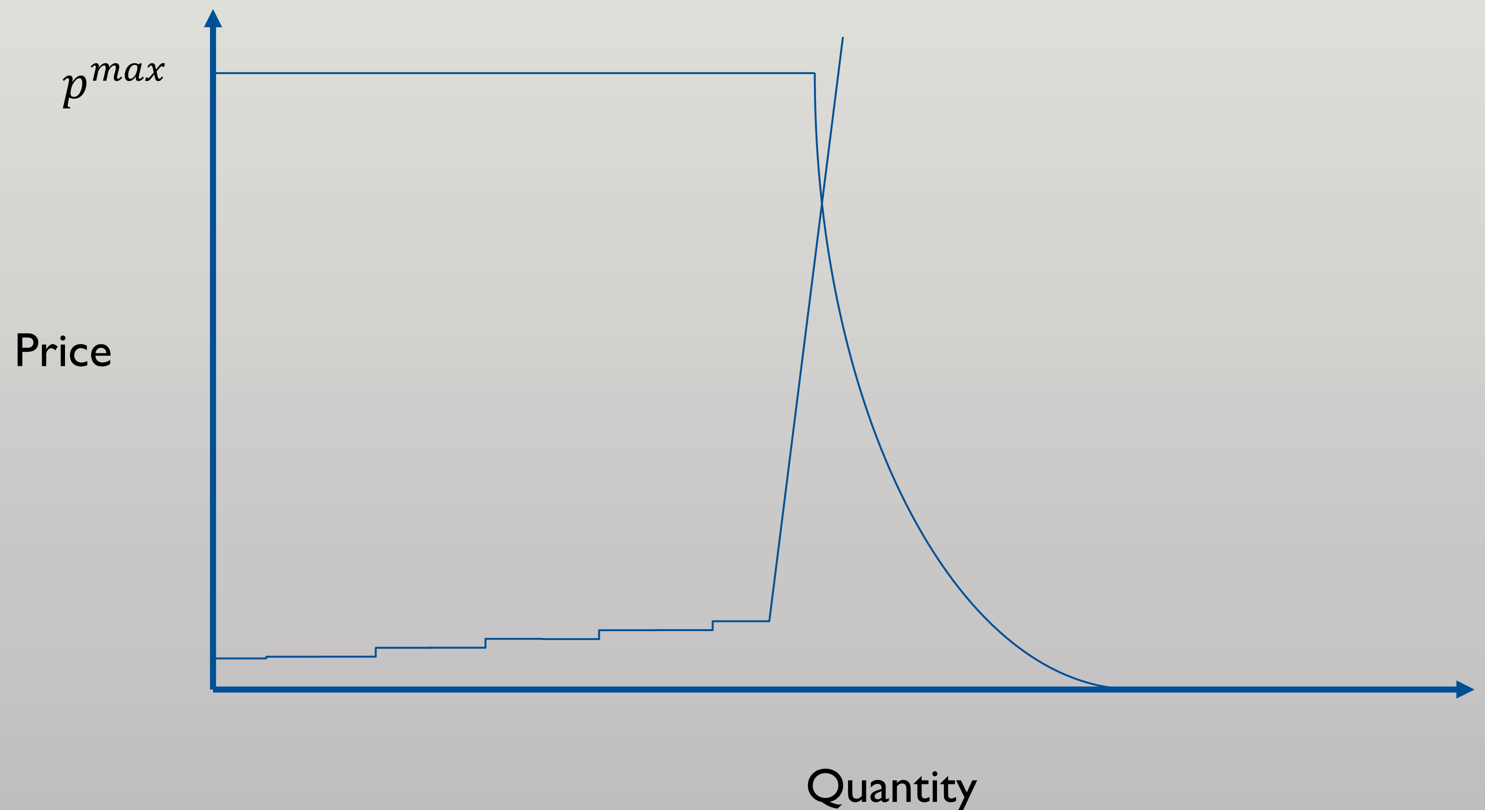
- Price formation
- Two generator model
  - Optimality
  - Pricing
- Larger system
  - Optimality
  - Pricing
- Discussion

Experimental design

- **Focus on CHP, LMP, and variants of ELMP, expanding price-setting logic to:**
  - **Only open cycle gas units**
  - **All gas units**
- **Approximate CHP (aCHP) by simply relaxing all binaries in the pricing run (also called "dispatchable")**
- **In ELMP, only allow online units to set price**
- **In ELMP, amortize start-up cost over minimum run time of generators**
- **Optimality gaps affect analysis in two ways:**
  - **Many possible near-optimal capacity mixes**
  - **Many possible near-optimal dispatch solutions**

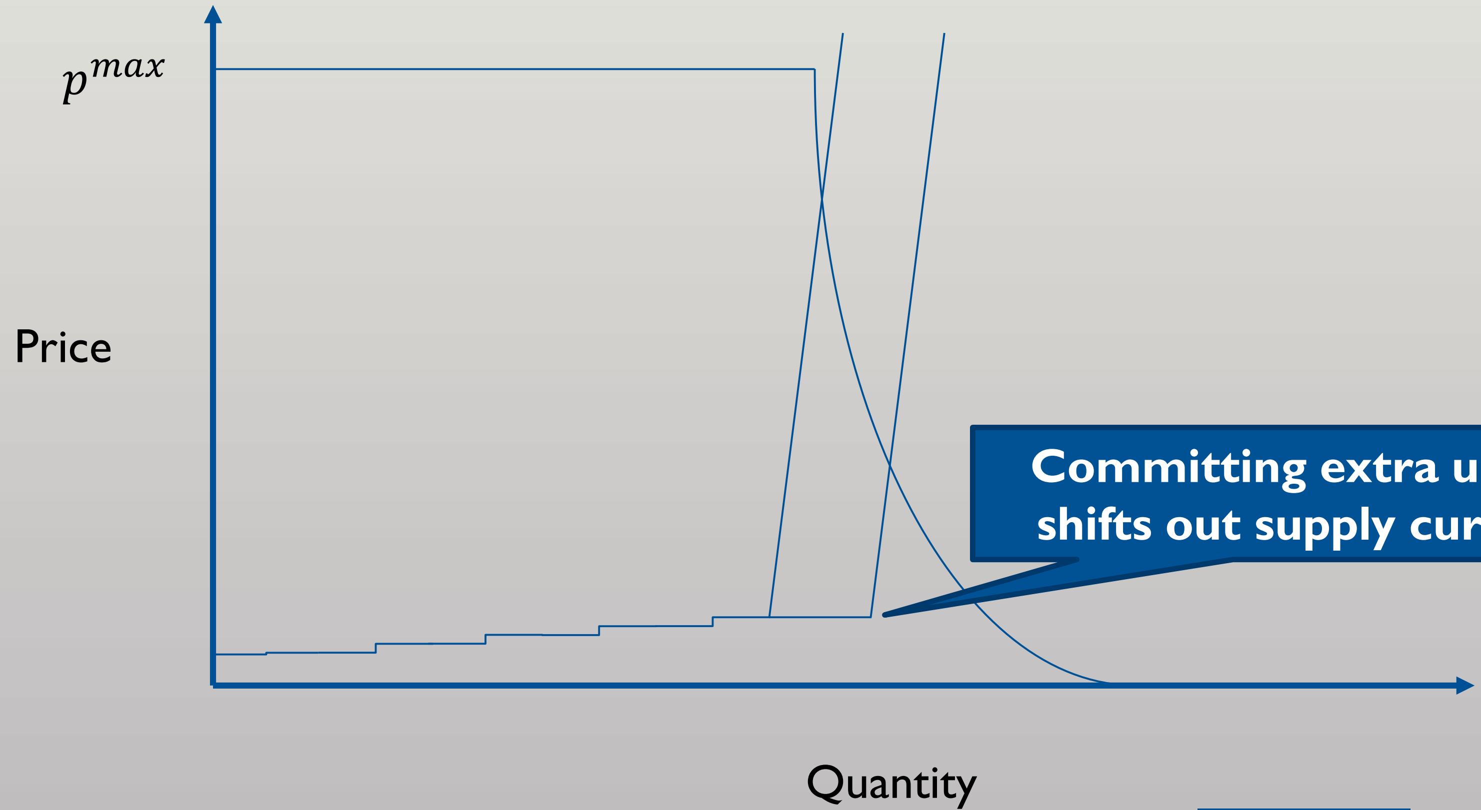
Solution pool

Steep demand curves and non-convexity lead to situations in which two near-optimal UC solutions have significant differences in prices



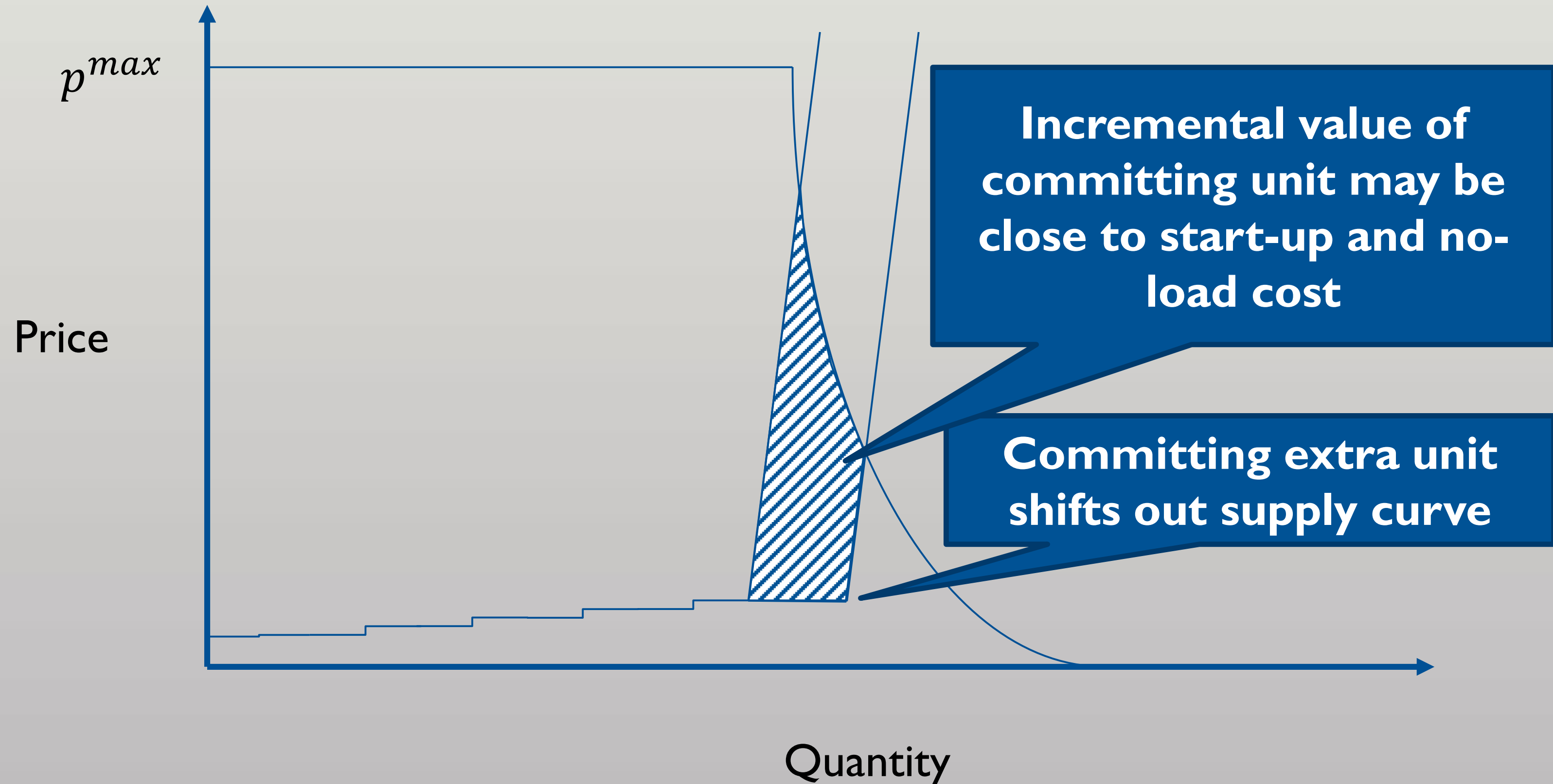
Solution pool

Steep demand curves and non-convexity lead to situations in which two near-optimal UC solutions have significant differences in prices



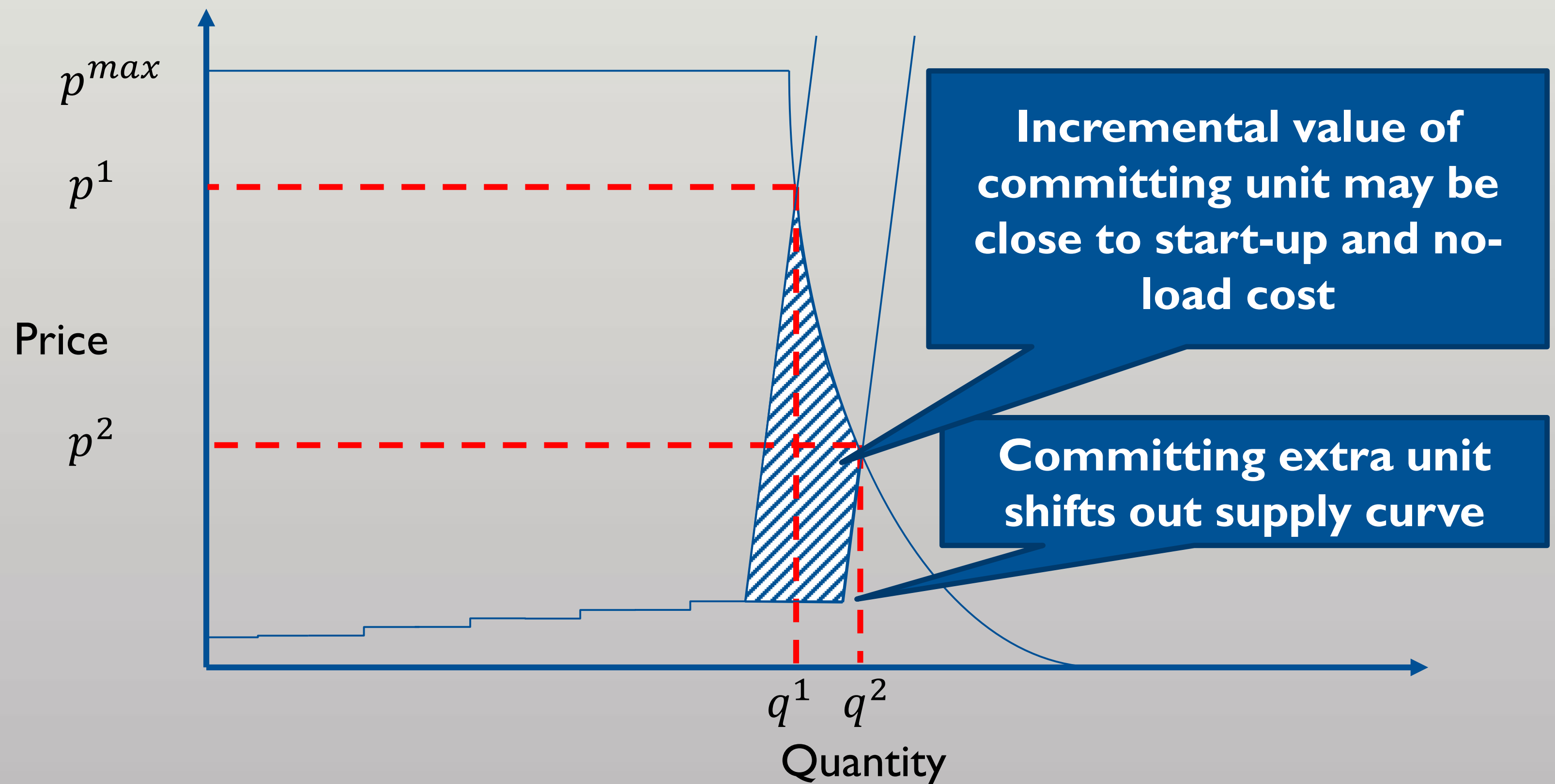
Solution pool

Steep demand curves and non-convexity lead to situations in which two near-optimal UC solutions have significant differences in prices



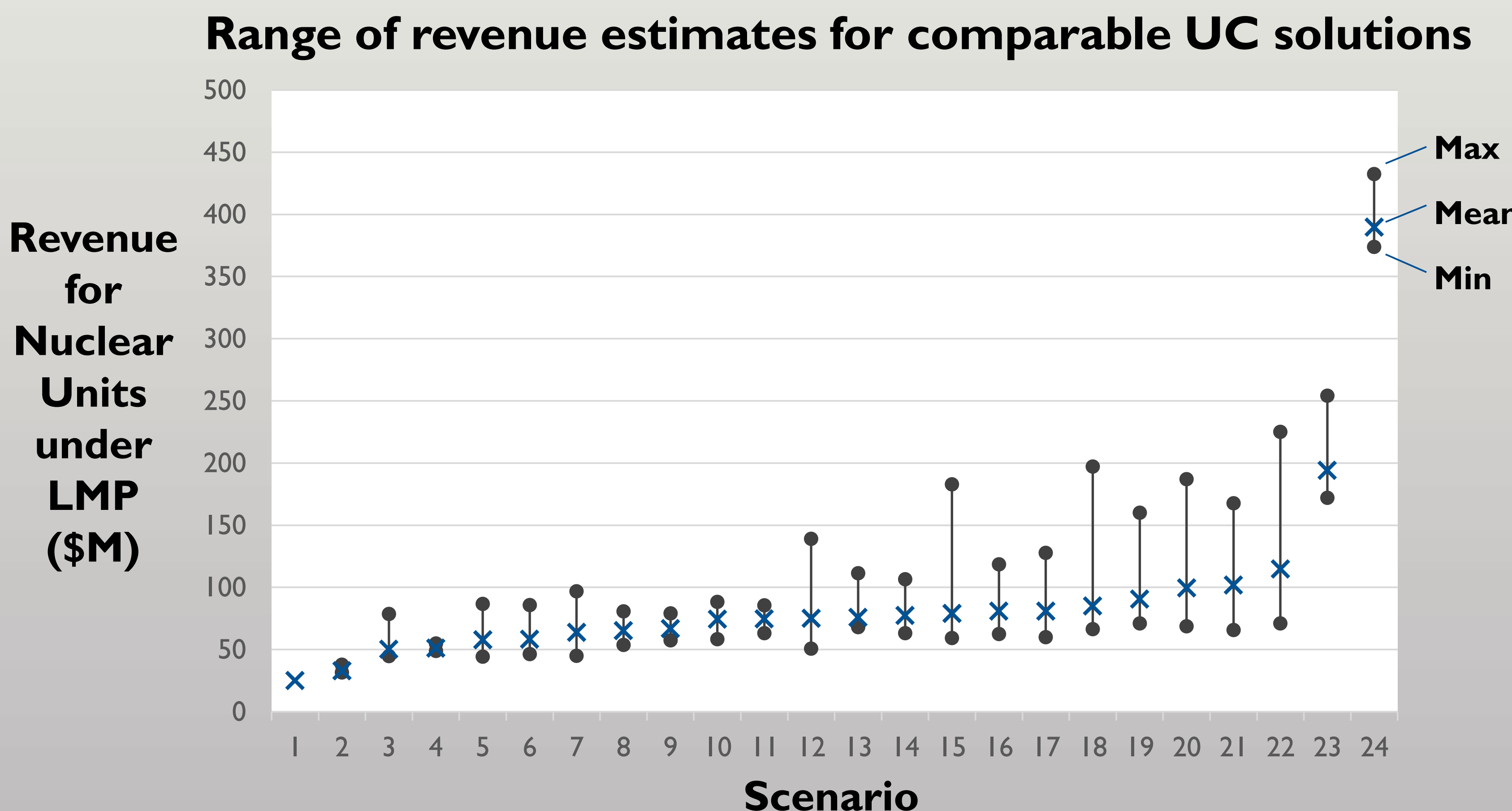
Solution pool

Steep demand curves and non-convexity lead to situations in which two near-optimal UC solutions have significant differences in prices



Solution pool

We calculate up to 20 near-optimal solutions for each UC instance to achieve better profitability estimates



Note: Optimality gap set to 2e-4; up to 20 solutions within 1e-3 of best found are included

McCormick
Northwestern Engineering

Profitability at system optimum

- Existence of multiple solutions for both stages presents challenges:
  - Which near-optimal solution to choose?
  - How much to trust profitability results?
- Noisy evaluations may result in solution with near-zero profit by chance
- Cannot expect zero-profit condition to be precisely satisfied due to non-convexity

Instead, try different test: can we plausibly describe any near-optimal solution as an equilibrium?

Equilibrium test

- **Assume we have calculated profit per unit for a set N of near-optimal capacity mixes**
- **Let $\pi^{g,s}(x^n)$ be the net margin for generation type g under pricing strategy s given capacity mix x^n**
- **Solve linear regression for each pricing strategy**

$$\beta^{g,s} = \arg\min_{\beta} \left\{ \sum_{n \in N} \left(\beta_0^{g,s} - \sum_{g' \in G} \beta_{g'}^{g,s} x_{g'}^n - \pi^{g,s}(x^n) \right)^2 \right\}$$

- **When limited to top 50 near-optimal solutions, regressions are high quality (median $R^2 = 0.96$)**

Equilibrium test

- **Use predictions $\hat{\pi}^{g,s}(x^n)$ as denoised profit estimates**
- **Locate a capacity mix anywhere within the convex hull of the top 50 solutions with near-zero profit for each generation type**

Proximity to equilibrium among near-optimal solutions

Prices	No Uplift	MWP	LOC
aCHP	0.5%	0.5%	0.3%
LMP	3.2%	3.9%	25.1%
ELMP–Gas Turbine	11.8%	11.9%	40.8%
ELMP–All Gas	33.1%	33.1%	43.7%

Equilibrium test

- **Use predictions $\widehat{\pi}^{g,s}(x^n)$ as denoised profit estimates**
- **Locate a capacity mix anywhere within the convex hull of the top 50 solutions with near-zero profit for each generation type**

Proximity to equilibrium among near-optimal solutions

Prices	No Uplift	MWP	LOC
aCHP	0.5%	0.5%	0.3%
LMP	3.2%	3.9%	25.1%
ELMP–Gas Turbine	11.8%	11.9%	40.8%
ELMP–All Gas	33.1%	33.1%	43.7%

Identified solutions can only plausibly be equilibria under aCHP or LMP

McCormick
Northwestern Engineering

Distributional effects of pricing strategies

- **Results are suggestive that LMP without uplift supports the optimal capacity mix**
- **Now can consider the distributional effect of introducing enhanced pricing or uplift**
- **For every pricing scheme and generation type, calculate net margin received relative to LMP:**

$$\sum_{n \in N} \left(\pi^{g,s}(x^n) - \pi^{g,lmp}(x^n) \right)$$

- **While net margin estimates vary, the benefits relative to LMP without uplift are stable**

Distributional effects of pricing strategies

Use of uplift payments disproportionately benefits gas generators

Increase in net margin relative to LMP with no uplift

	LMP+MWP	LMP+LOC
Wind	0%	0%
Solar	0%	0%
Nuclear	0%	0%
Coal	0%	1%
Combined Cycle Gas	3%	11%
Open Cycle Gas	5%	53%

Make-whole payments average 1.6% of total revenue under LMP+MWP

Paying lost opportunity costs results in outsized profits for gas units

Distributional effects of pricing strategies

Extending price setting logic to a new type of generation benefits resources with lower operating cost

Increase in net margin relative to LMP with no uplift

	LMP +MWP	ELMP–OCGT +MWP	ELMP–All Gas +MWP
Wind	0%	14%	37%
Solar	0%	14%	32%
Nuclear	0%	12%	29%
Coal	0%	11%	26%
CCGT	3%	12%	22%
OCGT	5%	10%	10%

Distributional effects of pricing strategies

Extending price setting logic to a new type of generation benefits resources with lower operating cost

Increase in net margin relative to LMP with no uplift

	LMP +MWP	ELMP–OCGT +MWP	ELMP–All Gas +MWP
Wind	0%	14%	37%
Solar	0%	14%	32%
Nuclear	0%	12%	29%
Coal	0%	11%	26%
CCGT	3%	12%	22%
OCGT	**5%**	**10%**	10%

Extending logic to OCGT increases its profit by 5%

Distributional effects of pricing strategies

Extending price setting logic to a new type of generation benefits resources with lower operating cost

Increase in net margin relative to LMP with no uplift

	LMP +MWP	ELMP–OCGT +MWP	ELMP–All Gas +MWP
Wind	0%	14%	37%
Solar	0%	14%	32%
Nuclear	0%	12%	29%
Coal	0%	11%	26%
CCGT	3%	12%	22%
OCGT	5%	10%	10%

Profit increases for other units by 9-14%

McCormick
Northwestern Engineering

Distributional effects of pricing strategies

Extending price setting logic to a new type of generation benefits resources with lower operating cost

Increase in net margin relative to LMP with no uplift

	LMP +MWP	ELMP–OCGT +MWP	ELMP–All Gas +MWP
Wind	0%	14%	37%
Solar	0%	14%	32%
Nuclear	0%	12%	29%
Coal	0%	11%	26%
CCGT	3%	12%	22%
OCGT	5%	10%	10%

Extending logic to CCGT increases its profit by 10%

Distributional effects of pricing strategies

Extending price setting logic to a new type of generation benefits resources with lower operating cost

Increase in net margin relative to LMP with no uplift

	LMP +MWP	ELMP–OCGT +MWP	ELMP–All Gas +MWP
Wind	0%	14%	37%
Solar	0%	14%	32%
Nuclear	0%	12%	29%
Coal	0%	11%	26%
CCGT	3%	12%	22%
OCGT	5%	10%	10%

Profit increases for cheaper units by 15-23%

McCormick
Northwestern Engineering

Distributional effects of pricing strategies

Extending price setting logic to a new type of generation benefits resources with lower operating cost

Increase in net margin relative to LMP with no uplift

	LMP +MWP	ELMP–OCGT +MWP	ELMP–All Gas +MWP
Wind	0%	14%	37%
Solar	0%	14%	32%
Nuclear	0%	12%	29%
Coal	0%	11%	26%
CCGT	3%	12%	22%
OCGT	5%	**10%**	**10%**

More expensive resource is not affected

Distributional effects of pricing strategies

Extending price setting logic to offline units in aCHP results in lower prices on average

Increase in net margin relative to LMP with no uplift

	aCHP	aCHP+LOC
Wind	-2%	-2%
Solar	-7%	-7%
Nuclear	-6%	-6%
Coal	-8%	-7%
Combined Cycle Gas	-10%	-10%
Open Cycle Gas	-5%	-4%

Wind and OCGT least impacted by reduction in prices

Generator lost opportunity costs are almost eliminated under aCHP

Outline

- Price formation
- Two generator model
  - Optimality
  - Pricing
- Larger system
  - Optimality
  - Pricing
- Discussion

McCormick
Northwestern Engineering

Discussion

- Results provide evidence for three main claims:
  - LMP without side payments supports the optimal capacity mix in the long term
  - Use of uplift benefits units with higher operating costs
  - Use of enhanced pricing benefits units with lower operating costs
- Also provide less conclusive results on CHP
  - Performs poorly in the two-generator system
  - Is able to support a near-optimal mix in the larger system despite lower prices than LMP
- Working paper: http://ssrn.com/abstract=3198423