Dynamic Pricing 2.0
The Grid-Integration of Renewables

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Dynamic Pricing 1.0 was designed primarily to clip peaks

- **Dynamic Pricing 1.0** includes time-varying rates, such as critical peak pricing (CPP) and peak time rebates (PTR)
Dynamic Pricing 1.0 has been quite successful in changing customer behavior

Enabling technology enhances customer response to *Dynamic Pricing 1.0*

PTR, CPP, & VPP Arc (N = 98)

Note: 2 Price only outliers were removed from the regression


IEEE PES GM 2013
The weak economic recovery following the recession has slowed load growth

- There is plenty of excess capacity in most parts of North America
- Some utilities don’t expect load to reach pre-recession levels until 2019 or 2024
- EIA keeps pushing out the date by which normal growth will resume
  - In fact, the “New Normal” might be demand growth at about half of the pre-recession value, in the 0.7 percent to 0.9 percent annual range
- Ergo, the impetus for clipping peaks has diminished

Source: Faruqui, Ahmad. Surviving Sub-One-Percent Growth, Electricity Policy, June 2013
Even when the economy recovers, popular support for dynamic pricing may not be there.

- Political issues have put a real damper on the rollout of dynamic pricing, despite the rollout of advanced metering infrastructure (AMI)
  - “I don’t want to do my laundry at 2 am” is a frequently voiced objection
  - Harm to low income customers, seniors and folks with disabilities round off the objections

- This assessment, based on a decade of pounding the pavement on the road to dynamic pricing, was confirmed recently with an email survey of 22 experts

- It is surreal which evokes *The Land of Mordor where the Shadows Lie* (J. R. R. Tolkien, The Lord of the Rings)
We stand at the cusp of a new era, dealing with the grid-integration of renewables

- Drivers include renewable portfolio standards and falling costs for renewable energy resources
- However, renewable resources have unique features that fundamentally change the way in which demand and supply need to be balanced
- Renewable resources don’t deliver energy around the clock, have very low capacity factors and are unpredictable and intermittent
Challenges in grid-integration of renewables

- **Intermittency**: wind and solar generation are highly variable, which leads to reliability concerns
  - Power plants have high startup and shutdown costs, so it is not easy for them to fill in when variable generation lags

- **Ramping**: wind and solar both have morning and evening production “ramps”
  - Fortunately, wind and solar have complementary load profiles

- **Overgeneration**: wind poses significant risk of overgeneration because wind farms produce the most electricity at night when loads are low

(See appendix for further discussion)

Grid-integration requires dynamic load response at all hours of the day

- This dynamic load response is achievable through a more flexible load shape and a transition from Dynamic Pricing 1.0 to Dynamic Pricing 2.0

**Dynamic Pricing 1.0**: CPP, VPP and PTR with some enabling technology and limited automation

**Dynamic Pricing 2.0**: Widespread real time pricing (RTP) with enabling technology and automation, including AMI and set-it-and-forget-it HVAC
RTP can help integrate renewables by creating around-the-clock flexibility in load
Dynamic Pricing 2.0 = RTP + fast response technologies

- Fast response technologies include:
  - Advanced metering infrastructure
  - Smart appliances
  - Home energy controllers
  - Energy storage
  - Batteries

- Integration requires the provision of ancillary services which include:
  - Spinning reserves
  - Nonspinning reserves
  - Regulation up and regulation down
Estimated Penetration of Advanced Metering, 2012

By 2020, the U.S. electric power sector is expected to add ~65 million advanced meters (which would reach ~47% of U.S. households) and ~40-80 GW of wind and solar capacity.


Automated customer response

- **Industrial load shifting** involves shifting industrial processes to off-peak hours, which requires extra storage infrastructure. For example, a paper mill could store pulp for processing during a later shift, or a wastewater treatment facility could store wastewater to process at night.

- **Programmable devices** allow customers to set their own demand schedules in response to price changes (i.e., programmable communicating thermostats (PCTs)).
  - A pilot study with programmable water heaters in Mason County, WA, achieved an 80% reduction in those water heaters’ contribution to peak load. Water heaters were set according to predetermined peak and off-peak periods (see appendix).

Energy Storage systems

♦ **Thermal energy systems (TES)** shift cooling loads. Good candidates for TES are industrial refrigerated warehouses, but residential systems may be available in the future. TES include:
  - Ice systems
  - Chilled water systems

♦ **Limited Energy Storage Resources (LESRs)** are generators with extremely fast response time. LESRs can act as a load (charging) or as a generator (discharging). LESRs include:
  - Flywheels
  - Batteries
  - Compressed air energy storage (CAES)
  - Plug-in electric vehicles

Source: Integration of Advanced Storage Technologies in the New York Wholesale Electricity Market. CIGRE. 2010
In 2009, the Australian state of Victoria began a $5 million initiative to launch the world’s first use of a Smart Grid for electric vehicle charging demand management.

The program began with a 3-month trial with 10 vehicles where vehicle owners were defaulted to a smart charging program, which automatically deferred charging to off-peak hours – customers could override this setting manually.

The study found that EV drivers could save $250/year (50% of total charging costs) by using the Smart Grid with no extra effort or loss of vehicle performance.

However, 44% of the 656 charging events occurred during on-peak times despite system automation to charge off-peak.

For the one customer with a TOU rate, only 36% of the chargings occurred on-peak.

Source: Demand management of electric vehicle charging using Victoria’s Smart Grid. Dius. May 2013
Incentivizing customers to shift loads

- Customers must face incentives to adopt automated demand response technologies and change their behavior to match variable generation.
- RTP is the most efficient way to provide this incentive.
- Evidence from several pilot studies shows that customers will change their load shape in response:
  - RTP pilot in Illinois
  - Olympic Peninsula pilot in Washington
  - PowerCentsDC pilot in the District of Columbia
A pocket history of dynamic pricing

**Dynamic Pricing 1.0**
- 1978: Florida Gulf Power begins a 3-period CPP tariff
- 1996: California utilities begin the Statewide Pricing Pilot with TOU and CPP rates
- 2000: PG&E begins its summer CPP program, SmartRate
- 2004: BGE introduces a PTR

**Dynamic Pricing 2.0**
- 1971: William Vickrey fathers the concept of RTP in *Responsive Pricing of Public Utility Services*
- 1981: Fred Scheppe describes a technology-enabled RTP future in *Homeostatic Control*
- 2003: Illinois General Assembly requires utilities to implement RTP programs
- 2007: Illinois’ Community Energy Cooperative begins ESPP, a residential RTP program
- 2006: Olympic Peninsula Project field tests RTP
- 2006: Pepco launches PowerCentsDC with CPP, PTR and hourly RTP pricing

**Going Beyond the Arc**
# RTP pilots

<table>
<thead>
<tr>
<th>Utilities/Organizations</th>
<th>Program Name</th>
<th>Year Started</th>
<th>Description</th>
<th>Enrollment</th>
<th>Impacts</th>
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</thead>
<tbody>
<tr>
<td>Commonwealth Edison, CNT Energy and Community Energy Cooperative</td>
<td>Energy-Smart Pricing Plan (ESPP)</td>
<td>2003</td>
<td>RTP with in-home price notification technology</td>
<td>1,500 participants (end of 2006)</td>
<td>Participants had a price elasticity of demand of -0.047 when prices were below $0.13/kWh and an elasticity of -0.082 when prices were above $0.13/kWh. Participants reduced summer electricity usage by 3% (2006)</td>
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<tr>
<td>Commonwealth Edison and CNT Energy</td>
<td>Residential Real Time Pricing (RRTP)</td>
<td>2007</td>
<td>Hourly RTP</td>
<td>10,000 participants (end of 2010)</td>
<td>Participants had a price elasticity of -0.22 when price alerts were sent at a 10 cents/kWh threshold. The elasticity was -0.06 when price alerts were sent at a 14 cents/kWh threshold. Participants reduced summer electricity usage by 5% and winter usage by 3.2% (2010)</td>
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<tr>
<td>US DOE and several northwestern utilities</td>
<td>Olympic Peninsula RTP</td>
<td>2006</td>
<td>RTP was one of several options. Supply and demand-side response technologies were utilized</td>
<td>112 participants (2006-2007)</td>
<td>Participants reduced peak load 5% when faced with a 750 kW constraint and 20% when faced with a 500 kW constraint (2006-2007)</td>
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<td>Smart Meter Pilot Program, Inc. and Pepco</td>
<td>PowerCents DC</td>
<td>2007</td>
<td>Program included hourly RTP option</td>
<td>231 participants on RTP (2008)</td>
<td>RTP participants achieved a 4% peak reduction in the summer and a 2% peak reduction in the winter</td>
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Simulation of a statewide application of RTP in New York

- Faruqui and Newell (2009) used elasticities from the Illinois RTP pilot to simulate the impact of an RTP rate structure in New York.
- In an average year, the top 1% of hours of electric demand (~90 hours) in New York State account for more than 10% of system peak demand.

Comparison of Flat and Hypothetical Dynamic Rates in New York City for 2010

We showed that RTP can reduce the peak load in New York City by 13-16%.

**Base Case:** No technology; elasticities unchanged

**Conservation Case:** Customers provided with in-home displays

**High Capacity Price:** Capacity prices are increased to reflect higher cost of entry

**High Elasticity:** Elasticities are twice as high as the base case to represent impact of enabling technology facilitating load shifting

<table>
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<tr>
<th>Dynamic Pricing Scenario</th>
<th>Change in System Peak</th>
<th>Change in New York City Peak</th>
<th>Change in Long Island Peak</th>
<th>Change in Average Load</th>
<th>150 Hours w/Max Δ Load</th>
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<tr>
<td></td>
<td>All Hours (MW) (%)</td>
<td>All Hours (MW) (%)</td>
<td>All Hours (MW) (%)</td>
<td>All Hours (MW) (%)</td>
<td>150 Hours (MW) (%)</td>
</tr>
<tr>
<td>Base Case</td>
<td>(3,418) (10%)</td>
<td>(1,514) (13%)</td>
<td>(590) (11%)</td>
<td>84 (0.4%)</td>
<td>(1,897) (6%)</td>
</tr>
<tr>
<td>Conservation</td>
<td>(3,751) (11%)</td>
<td>(1,514) (13%)</td>
<td>(604) (11%)</td>
<td>(288) (1.5%)</td>
<td>(2,158) (7%)</td>
</tr>
<tr>
<td>High Capacity Price</td>
<td>(4,282) (13%)</td>
<td>(1,671) (14%)</td>
<td>(776) (14%)</td>
<td>176 (1.0%)</td>
<td>(3,147) (11%)</td>
</tr>
<tr>
<td>High Elasticity</td>
<td>(4,603) (14%)</td>
<td>(1,961) (16%)</td>
<td>(779) (14%)</td>
<td>130 (0.7%)</td>
<td>(3,606) (12%)</td>
</tr>
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AEP Ohio is moving towards Dynamic Pricing 2.0

♦ In 2010, AEP Ohio installed 110,000 Smart Meters

♦ Now, customers can choose among an array of TOU and dynamic pricing options

♦ Customers can also use their Smart Meter to see their electricity usage and costs in real time

In 1981, MIT’s Fred Schweppe published *Homeostatic Control: The Utility/Customer Marketplace for Electric Power*

In Schweppe’s formulation, *homeostatic control* is the ability to maintain internal equilibrium between electricity supply and electricity demand through technological and economic means.

It is based on two principles:
- Customer independence
- Feedback between the customer and utility

The idea of flexible load shapes was also discussed in Clark Gellings’ 1982 paper on Demand-Side Planning.
Schweppe’s Marketplace Controller sets spot prices at 5-minute and 24-hour intervals

Under the present system, the regulatory commission sets the rates using: \( (\text{revenue}) = (\text{costs}) + (\text{reasonable rate of return}) \)

A Marketplace Controller can compute spot prices the same way
Schweppes’s technology

- Technology to facilitate homeostatic control needs to meet two criteria:
  - It can check if the customer service is being delivered (i.e., building temperature is being maintained)
  - It can check system frequency, voltage and power flows

- By 1981, MIT had already developed this technology in the Frequency Adaptive Power Energy Rescheduler (FAPER)
  - FAPER was a small microprocessor, which accepts a temperature or water level measurement, measures local frequency and then takes the appropriate action
The Schweppian future

6:00 am  Computer gets hot water ready for shower when consumer wakes up

7:00 am  Computer displays its energy use plan for next 24 hours based on predicted weather, spot price patterns and owner's average lifestyle, which computer has learned (think Nest thermostat)

10:00 am Latest spot price and weather forecasts cause computer to pre-cool parts of the house so it can "coast" during the afternoon

12:00 pm Consumer calls computer to say guests are spending the night. Computer incorporates air conditioning the guest room into its strategy

3:00 pm  A large quantity of supply is lost due to a storm. Computer reacts to very high spot prices by turning off everything except the refrigerator, freezer and itself

“The future, though imminent, is obscure” – Winston Churchill
Prerequisites of success

♦ A major challenge in implementation of Dynamic Pricing 2.0 will be overcoming consumer apathy by educating consumers about dynamic pricing and encouraging them to adopt enabling technology.

♦ Important components of Dynamic Pricing 2.0 have already arrived: AMI and automation technologies are available, and RTP is proven across many settings.

♦ Smart metering and smart appliances are on the way, but consumers must be engaged with these new opportunities.

♦ Despite the availability of technology and the feasibility of RTP, this process will take time to generate mass appeal among the many stakeholders that govern ratemaking.
Some fundamental questions need to be answered

- Should utilities or system operators directly control customer end use loads?

- To complement RTP, should automation and control technologies be provided by the utility, the load serving entity or competitive retail providers, or should consumers be expected to buy it on their own?

- Will customer responses to dynamic RTP be sufficiently reliable for homeostatic control to be actualized?
The way forward

While a few RTP pilots have been done, and while some have featured enabling technologies, they were not specifically focused on grid-integration of renewables.

We need a new generation of pilots focused on Dynamic Pricing 2.0 that will allow fast and flexible load shaping around the clock.

There is a lot we can learn from previous pilots with time-of-use and Dynamic Pricing 1.0; e.g., treatment and control groups should be selected randomly and be observed before-and-after the activation of pricing treatments to yield valid conclusions.
References


References (cont’d)


Ahmad Faruqui is a principal with *The Brattle Group* who specializes in analyses and strategy relating to the customer. He has helped design, monitor and evaluate energy efficiency investments for a wide range of electric and gas utilities and testified before a dozen state and provincial commissions and legislative bodies. He has also worked for the Alberta Utilities Commission, Edison Foundation, the Edison Electric Institute, the Electric Power Research Institute, the Federal Energy Regulatory Commission, the Ontario Energy Board and the World Bank. His work has been cited in publications such as *The Economist*, *The New York Times*, and *USA Today*, and he has appeared on Fox News and National Public Radio. The author, co-author or editor of four books and more than 150 articles, papers and reports, he holds a Ph.D. in economics from The University of California at Davis and B.A. and M.A. degrees in economics from The University of Karachi.
APPENDIX
The Renewable Energy Challenge: Ramping

Forecast for Ontario’s IESO Net Load on a Typical Winter Day in 2015

- Wind and solar both have morning and evening production “ramps”
- For example, PV systems can experience a change in output of +/- 50% over 90 seconds
- Fortunately, wind and solar have complementary load profiles


Wind and solar generation are highly variable, which leads to reliability concerns. Power plants have high start-up and shut-down costs, so it is not easy for them to fill in when variable generation lags.

The Renewable Energy Challenge: Intermittency

- The largest variability and uncertainty in renewable generation occurs over time periods of 1 to 12 hours, time scales that allow demand response opportunities for mass market customers.

- Also, the variability over short time scales is much less: Over one minute, for example, the aggregate variability of wind plants has been measured at less than 0.2% of the nameplate capacity.

Renewable Energy Challenge: Overgeneration

As a result of ramping and intermittency, wind and solar increase risk of overgeneration.

Wind poses significant overgeneration challenges because wind plants produce the most electricity at night when loads are low.

Overgeneration is also a concern during large/steep ramps, which will be exacerbated by increasing renewable energy portfolios.

Renewable Energy Challenge: Overgeneration

♦ In California, afternoons currently see a 3,000-4,000 MW ramp in a period of an hour. By 2020, this afternoon ramp is projected to increase to 7,000-8,000 MW in an hour.


♦ In 2009, NYISO addressed wind overgeneration by establishing a rule to direct wind resources to reduce their output when necessary and economically appropriate.

In 2010, 74 automated water heaters were installed in homes in Mason County, WA.

The programmable water heaters had these characteristics:

- The water heaters were scheduled to be off during peak hours (7:30 to 8:30AM and 5:30 to 7:30PM).
- The water heaters were scheduled to preheat 6:30 to 7:30AM and 4:30 to 5:30PM.
- Water heaters followed the renewable energy availability during the rest of the day.
- Water heaters had a random delay to avoid coming online at the same time.

End result was an 80% reduction in those water heaters’ contribution to peak load.

RTP in Illinois: ComEd and CNT Energy

Commonwealth Edison and CNT ESPP:

- In 2003, ComEd and CNT Energy launched the nation’s first day-ahead RTP program with hourly prices. The program, Community Energy Cooperative’s Energy-Smart Pricing Plan (ESPP), was offered on an opt-in basis. By the end of 2006, 1,500 customers were enrolled in the program.
- Participants had a price elasticity of -0.047 when prices were below $0.13/kWh and a price elasticity of -0.082 when prices were above $0.13/kWh.
- When participants were provided with technology (a light that glowed different colors with different price levels), the elasticity was -0.067.
- Program participants reduced summer electricity usage by 3%.

More RTP in Illinois: ComEd RRTP

♦ Commonwealth Edison RRTP:

- In 2007, ComEd began the Residential Real Time Pricing (RRTP) program with hourly prices. By the end of 2010, the program had over 10,000 participants.
- Using a log model, Navigant Consulting found a price elasticity of demand of -0.22 for participants who received price alerts at a 10 cents/kWh threshold. The elasticity was -0.06 for participants who received price alerts at a 14 cents/kWh threshold (2010).
- Program participants reduced summer electricity usage by 5% and winter usage by 3.2% (2010).

Ameren Illinois Utilities:

- In 2007, Ameren Illinois Utilities launched a real-time-pricing program on an opt-in basis. By the end of 2012, the program had 1,262 participants (down from 7,422 in 2009).
- Rather than providing participants with automated response technologies, Ameren sent customers high price alerts whenever the day-ahead prices indicated that there would be one or more hours over 13 cents/kWh.
- Summit Blue Consulting found that the overall customer elasticities were -4.3% in 2008 and -2.3% in 2009.
- In 2012, the average participant decreased consumption 464 kWh during the summer and increased consumption 376 kWh during the winter.

Between 2006 and 2007, 112 households participated in a field test of RTP and demand response in Washington and Oregon. Participants were evenly split between RTP, TOU rates, fixed pricing, and a control group.

Technological resources included five 40-HP water pumps at two municipal water pumping stations, two distributed diesel generators, and programmable water and space heaters at each of the 112 participating households. All of these resources could be programmed to automatically respond to project price signals.

The project achieved a 5% peak load reduction when customers were faced with a 750 kW constraint and a 20% peak load reduction when customers were faced with a 500 kW constraint.

In 2007, Pepco and Smart Meter Pilot Program, Inc. initiated PowerCentsDC to test consumer response with RTP, smart meters and smart thermostats.

231 customers participated in hourly pricing during 2008.

RTP customers achieved a 4% peak reduction in the summer and a 2% peak reduction in the winter.

# Brattle’s Areas of Expertise

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