

# The Cost-Effectiveness of Demand Response in NSP's Service Territory

PRESENTED TO

Northern States Power (NSP)

PRESENTED BY

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## Introduction

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### **In 2014, Brattle conducted a bottom-up assessment of demand response (DR) potential in Minnesota, but did not evaluate DR cost-effectiveness**

- The study identified around 400 MW of traditional DR “technical potential” in the sense that it did not account for the cost-effectiveness of the DR measures
- These estimates of DR potential were not estimates of economic potential; they were inputs to the resource planning modeling process

### **Subsequently, a range of views on cost-effective DR potential emerged in Minnesota**

- NSP has estimated between 71 and 130 MW of incremental economic potential
- The PUC has established a requirement of 400 MW of additional DR capability by 2023 and consideration of 1,000 MW of new DR by 2025

### **The purpose of this presentation is to revisit the 2014 Potential Study and provide Brattle’s assessment of the amount of cost-effective DR available from that study**

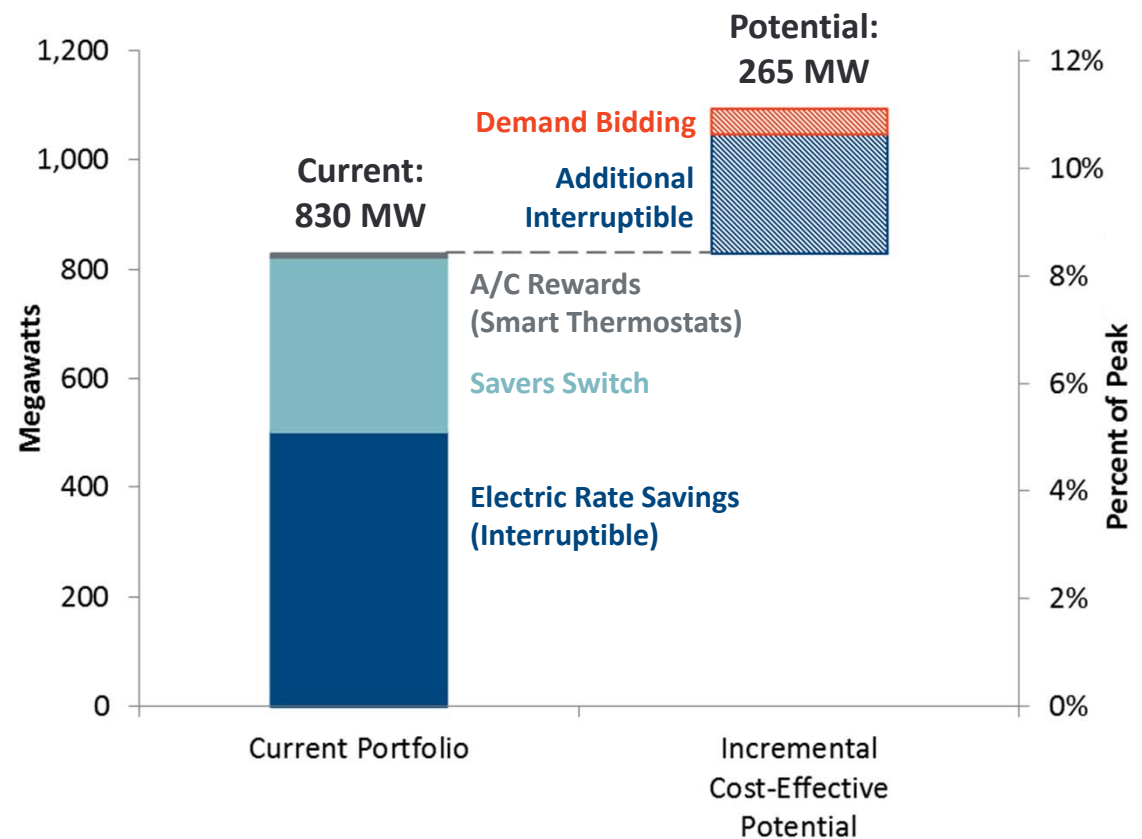
Note: 71 MW economic potential estimate identified by Staff in an October 2016 briefing paper, based on review of NSP IRP modeling data. 130 MW based on preliminary cost-effectiveness analysis conducted by NSP in 2015 (prior further detailed IRP modeling), as filed in Appendix N to the Resource Plan.

# Key Findings

## Comments

- NSP’s current DR portfolio is one of the largest in the U.S.
- The market for traditional cost-effective DR in MN may be approaching saturation
- We identified 260 MW of incremental cost-effective DR potential among the options considered in the 2014 Study
- This estimate is subject to uncertainty; through probabilistic simulation, we estimate that there is a 75% chance the potential is under 300 MW
- There may be additional value in around-the-clock load flexibility (not quantified in this study)

## Existing DR Capability and Cost-Effective Potential



Notes: Potential shown for 2023. Projected 2023 peak load of 9,848 MW was used as basis for estimating % of peak impact. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017.

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## Key findings (cont'd)

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**In spite of the limited amount of traditional incremental cost-effective DR identified in this study, there may be more value in alternative forms of demand flexibility**

### **Emerging opportunities for “demand flexibility” include**

- Renewables integration: Providing a suite of DR programs that mimic energy, capacity, and a range of ancillary services in response to rapidly changing system conditions
- Distribution benefits: Geographically-targeted programs designed to defer the need for expensive upgrades in capacity-constrained locations on the system

### **Accordingly, the definition of demand response should be expanded and assessed in the next IRP**

- Emerging DR programs include thermal storage (e.g., grid-integrated water heaters), bring-your-own-thermostat programs, behavioral DR, electric vehicle charging control, and AMI-enabled time-varying pricing
- The definition could also be expanded to include options such as distributed battery storage, combined heat-and-power (CHP), and some types of energy efficiency

# Organization of the presentation

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- 1. A national perspective on NSP's DR portfolio**
- 2. Best practices for quantifying DR cost-effectiveness**
- 3. Our assessment of NSP's cost-effective DR potential**
- 4. Moving forward with DR in Minnesota—initial thoughts**

# A National Perspective on NSP's DR portfolio

## We benchmarked NSP's DR portfolio against other utilities in the U.S.

**For context, it is helpful to first understand how NSP's portfolio compares to those of other utilities**

**The benchmarking analysis relied largely on DR program data from two sources: the FERC and the EIA**

- From 2006 to 2012, FERC conducted a bi-annual survey of utility DR programs, including significant detail on program type, enrollment, capability, etc.
- The EIA annually collects basic aggregate data on DR enrollment and capability by major customer class; the most recent data is from 2015
- While the FERC data is older, it appears to contain fewer reporting errors and is therefore the primary data source we relied on in our analysis
- We do not anticipate that changes in utility DR programs since 2012 would materially change the broad findings of the benchmarking analysis

See Appendix A for additional detail on benchmarking analysis

# NSP currently has 830 MW of DR capability

## Comments

### Savers Switch:

Air-conditioning direct load control (DLC) program, mostly targeting residential and small C&I customers

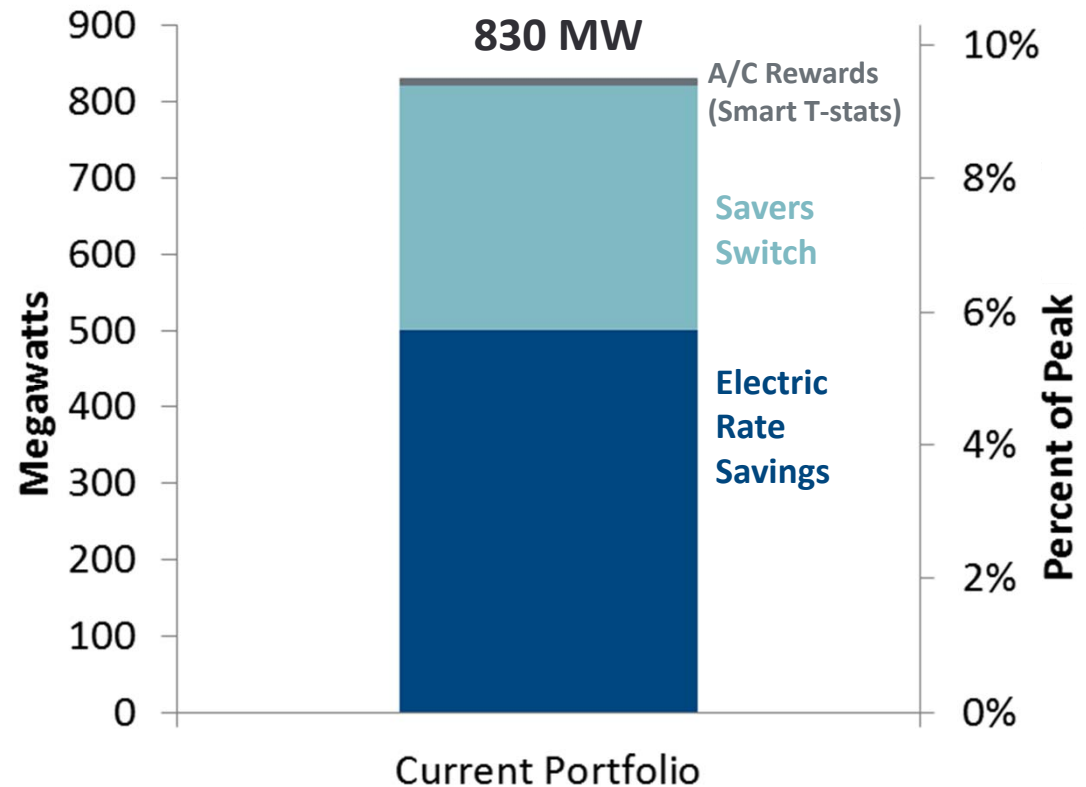
### A/C Rewards:

Direct load control for customer-owned smart thermostats (residential)

### Electric Rate Savings:

Interruptible tariff, targeting medium to large C&I customers

## NSP DR Capability (2017)



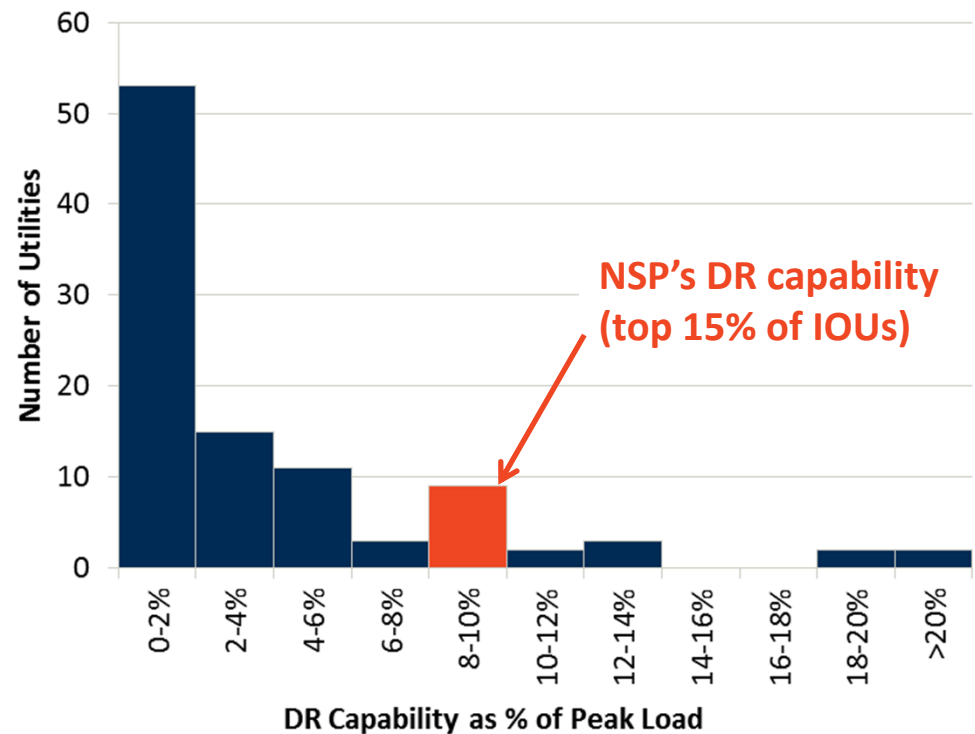
Notes: Percent of peak impact shown relative to actual 2016 peak load of 8,774 MW. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017. See appendix for further description of programs.

# NSP's DR capability is in the top 15% of U.S. IOUs

## Comments

- NSP's residential A/C load control program is the **2<sup>nd</sup>** most highly subscribed DR program in the country
- Around half of all eligible households are participating in NSP's Saver's Switch program
- In terms of absolute megawatts, NSP's portfolio is the **8<sup>th</sup>** largest program in the country; as a % of peak demand, it is ranked **11<sup>th</sup>**

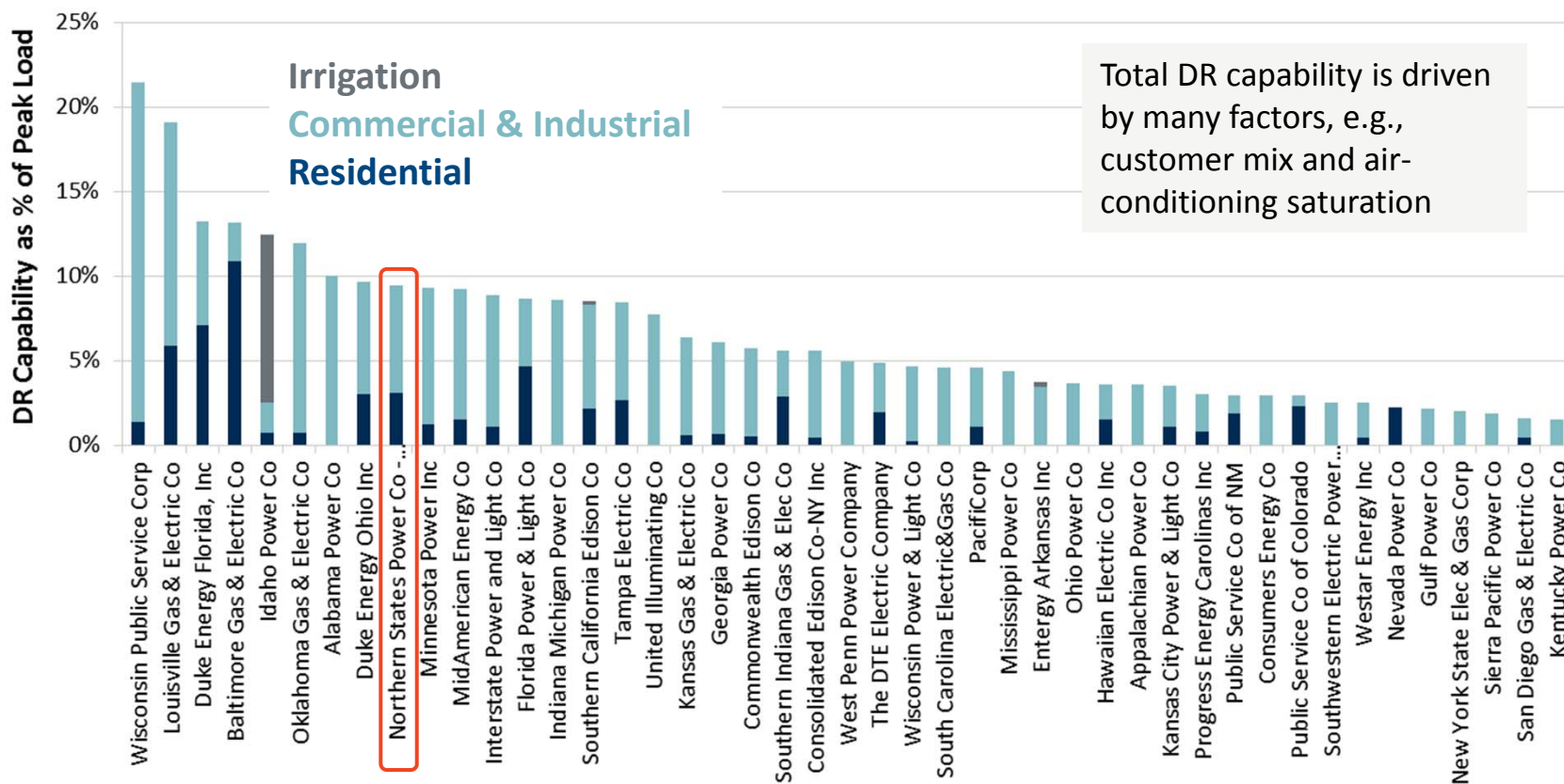
## Distribution of DR Capability Among All U.S. IOUs



Sources and Notes: FERC, 2012 Assessment of Demand Response and Advanced Metering and EIA 861 peak load data. Sample of 100 U.S. IOUs. Excludes IOUs that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP's capability calculated as current portfolio divided by 2016 peak load.

# NSP ranks near the top of the largest IOU DR portfolios in terms of % of peak load

## DR Capability of 45 IOUs with Largest Programs (as % of Peak Demand)



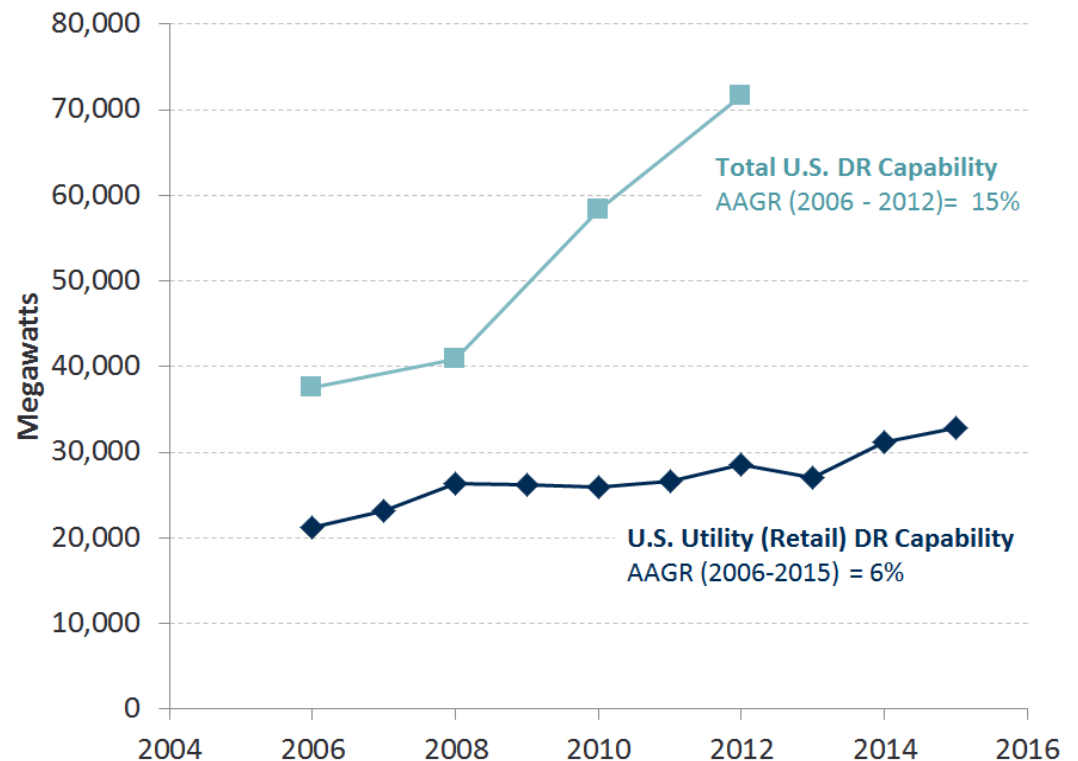
Sources and Notes: FERC, 2012 Assessment of Demand Response and Advanced Metering and EIA 861 peak load data. Sample of 100 U.S. IOUs. Excludes IOUs that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP’s capability calculated as current portfolio divided by 2016 peak load.

# National DR growth has been driven by ISO/RTO programs – much more than by utility programs

## Comments

- There is sometimes a misperception that utility DR programs were the primary drivers of DR growth over the past decade
- While U.S. DR capability grew at an annual rate of **15%** between 2006 and 2012, most of this growth was driven by programs operated by ISOs and RTOs
- PJM accounted for roughly half of the total ISO/RTO growth, in part due to significant efforts to integrate DR into its capacity market, which offered significant payments for demand reductions
- Utility DR programs only grew at an annual rate of **6%** during that time

## Distribution of DR Capability Among all U.S. IOUs



Sources and Notes: Total U.S. DR Capability reflects data reported in 2006–2012 FERC surveys, which include DR capability provided by aggregators, power marketers, and state and federal energy authorities. U.S. Utility (Retail) DR Capability reflects data reported in 2006–2015 EIA-861 data.

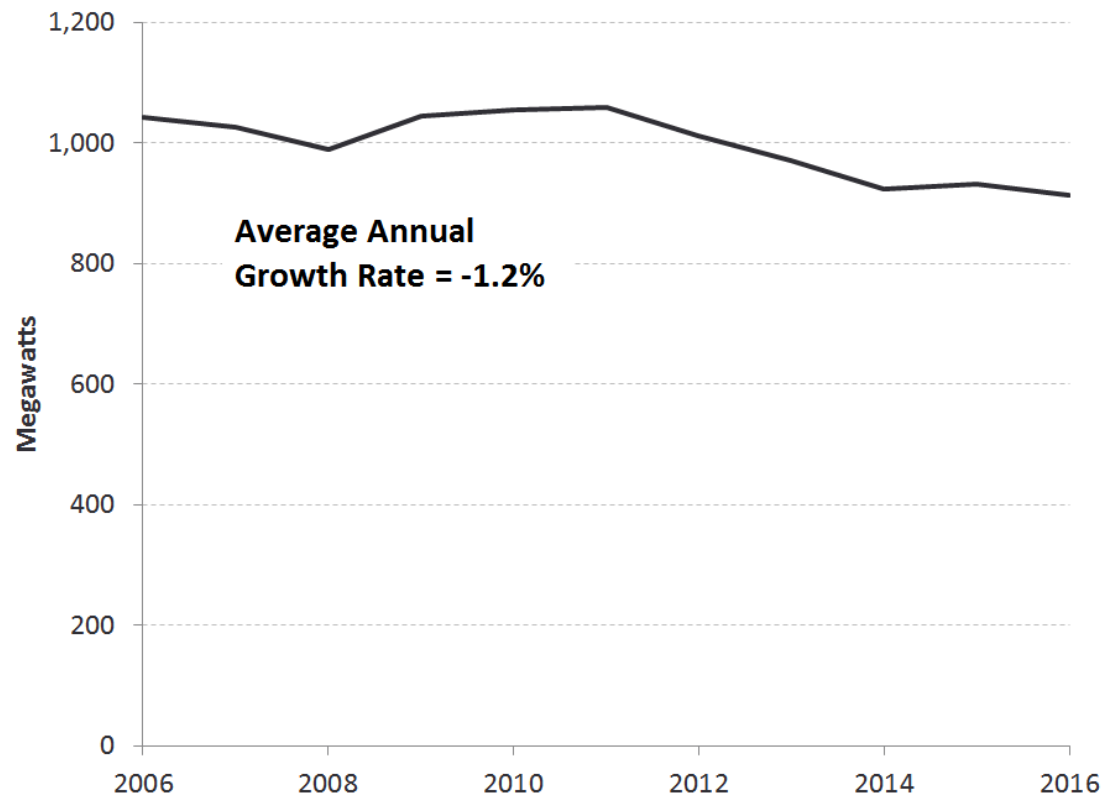
# Relative to modest national growth in utility DR over the past decade, NSP's DR capability has dipped

## Comments

### A few explanations:

- EPA constraints on the use of backup generation as DR, imposed in 2013
- Increased utilization of the interruptible tariff program in 2016, leading to some drop-outs
- Allowing DR participants to lower their contractually committed load reduction level in anticipation of more frequent program use
- Possibly approaching market saturation due to high enrollment rates (relative to other U.S. utilities)

## Historical NSP DR Capability



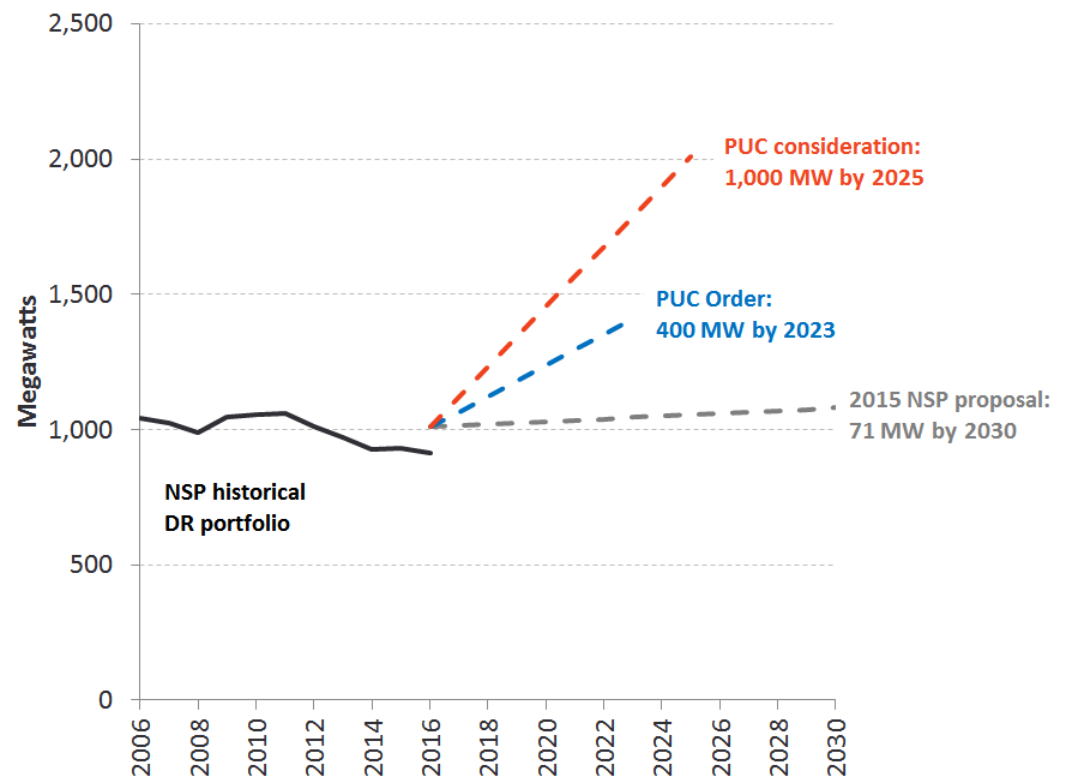
Sources and Notes: Data provided by NSP. Values shown are for entire NSP service territory.

# To what extent can NSP’s DR portfolio cost-effectively grow beyond recent levels?

## Comments

- NSP proposed to reverse the recent historical decline with 71 MW of DR growth
- The PUC has ordered NSP to pursue 400 MW of additional DR
- The PUC’s interest in 1,000 MW of new DR would significantly exceed historical observed growth rates among U.S. utilities
- **In the remainder of this presentation, we explore where NSP’s cost-effective DR potential falls on this spectrum**

## DR Proposals Relative to Historical Growth



Sources and Notes: Data provided by NSP. Projections of growth were established by the PUC and NSP relative to the size of the 2014 DR portfolio; therefore, they do not align with 2016 reported values.

# Best Practices for Quantifying the Cost-Effectiveness of DR

# There are two established options for determining the cost-effectiveness of DR

## 1. Incorporate DR options into the resource planning model

- Dynamically accounts for the advantages and disadvantages of DR relative to supply-side options
- However, it is difficult to implement comprehensively due to modeling and computational limitations

## 2. Conduct a detailed cost-effectiveness screening

- Performed outside of the IRP model
- Commonly used in regulatory proceedings to evaluate DR and EE cost-effectiveness (i.e., the Total Resource Cost test)
- Has the advantage of transparency, while still relying on the same cost and operational assumptions used in the IRP model
- Allows for a broader range of sensitivity cases around uncertain variables

We rely on the screening-based approach

## The value of DR is assessed based on its ability to avoid the need for new peaking generation

The DR programs analyzed in the 2014 Potential Study are most appropriately considered substitutes for new combustion turbine (CT) capacity

CTs are “peaking” units with relatively high variable costs; as a result, they typically only run up to **a few hundred hours of the year**, when electricity demand is very high and/or there are system reliability concerns

Similarly, use of DR programs in the U.S. is typically limited to **<100 hours per year** – this constraint is either written into the tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs

In contrast, new intermediate or baseload capacity (e.g., gas-fired combined cycle) has a higher capital cost and lower variable cost than a CT, and therefore will run **thousands of hours per year**

The DR programs considered in the 2014 Potential Study cannot feasibly avoid the need for new intermediate or baseload capacity, because they cannot be called during a sufficient number of hours of the year; energy efficiency is a more comparable demand-side alternative to these resource types since it is a permanent load reduction that applies to a much broader range of hours

Note: For more data on the number of interruptions per year in a typical U.S. DR program, see SEPA, “2017 Utility Demand Response Market Snapshot,” October 2017.

# Comparing traditional DR to a new CT

**Even though traditional DR is most comparable to a CT, there are operational differences between these resources that must be taken into account**

	Demand Response	New Combustion Turbine
<b>Total hours of availability</b>	Roughly 100 hrs/yr	Roughly 8,200 hrs/yr (accounting for planned and unexpected maintenance)
<b>Seasonal availability</b>	A/C: Summer only; Other programs: year-round	Year-round
<b>Daily window of availability</b>	A/C: roughly 2 to 7 pm; Other programs: business hours	Any hour of day
<b>Other considerations</b>	Must try to limit consecutive interruptions	None
<b>Variable cost</b>	\$0/MWh	\$40/MWh
<b>Fixed cost</b>	\$30-250/kW-yr	\$50-70/kW-yr

CTs can run any hour of the year (subject to outages), whereas the timing of DR use is constrained

DR costs are largely fixed incentive payments and/or up-front investment in technology; there is not usually a cost to call a DR event

DR fixed costs include incentives, equipment, marketing & administration. CT fixed cost based on values reported in NSP's IRP. CT variable cost assumes \$3/MMBtu delivered gas price, and CT heat rate of 9.75 MMBtu/MWh and VOM of \$10/MWh, consistent with an 'advanced CT' in EIA's *Updated Capital Cost Estimates for Utility Scale Generating Plants* (2013).

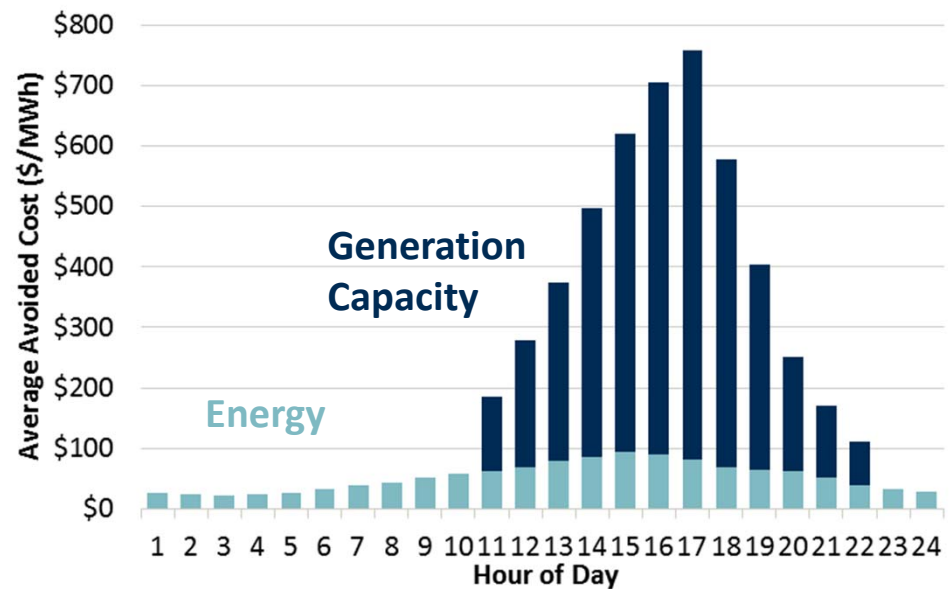
In addition to operational differences, considerations such as the dependability of the resource may also factor into the decision. See Appendix B for additional discussion of DR operational constraints

# We account for the operational constraints of DR in our cost-effectiveness analysis

## Comments

- Capacity costs are allocated to hours of the year proportional to the risk of capacity shortages in those hours
- In the base scenario, capacity costs are allocated to the top 100 system load hours of the year (this assumption is tested through sensitivity analysis)
- The allocation is roughly proportional to each load hour’s share of total load in the hours (i.e., more capacity cost is allocated to the top load hour than the 100<sup>th</sup>)
- A similar approach has been used in California’s DR cost-effectiveness protocols, and in the state’s time-dependent valuation (TDV) metric for quantifying the value of energy efficiency
- The hourly allocation of capacity costs is added to 2013 hourly MISO energy market prices for NSP’s service territory

## Allocation of Marginal Costs: 2023 Average over Days With Capacity Value



Notes: On days without peak capacity constraints, there is no allocation of capacity value. Avoided costs shown for 2023 in nominal dollars. 2013 energy prices escalated to 2023 dollars assuming 2.2% inflation.

## Avoided T&D capacity costs are also included in the analysis

### **Avoided T&D capacity costs are only sometimes included in assessments of DR cost-effectiveness**

- Depends on DR program objectives and the physical characteristics of the utility system
- Requires higher frequency of interruptions due to lack of coincidence between transmission and distribution system peaks

### **Nationally, T&D investment needs are increasingly being driven by factors other than peak demand growth, limiting the T&D value of peak demand reductions. Factors commonly driving T&D investment include**

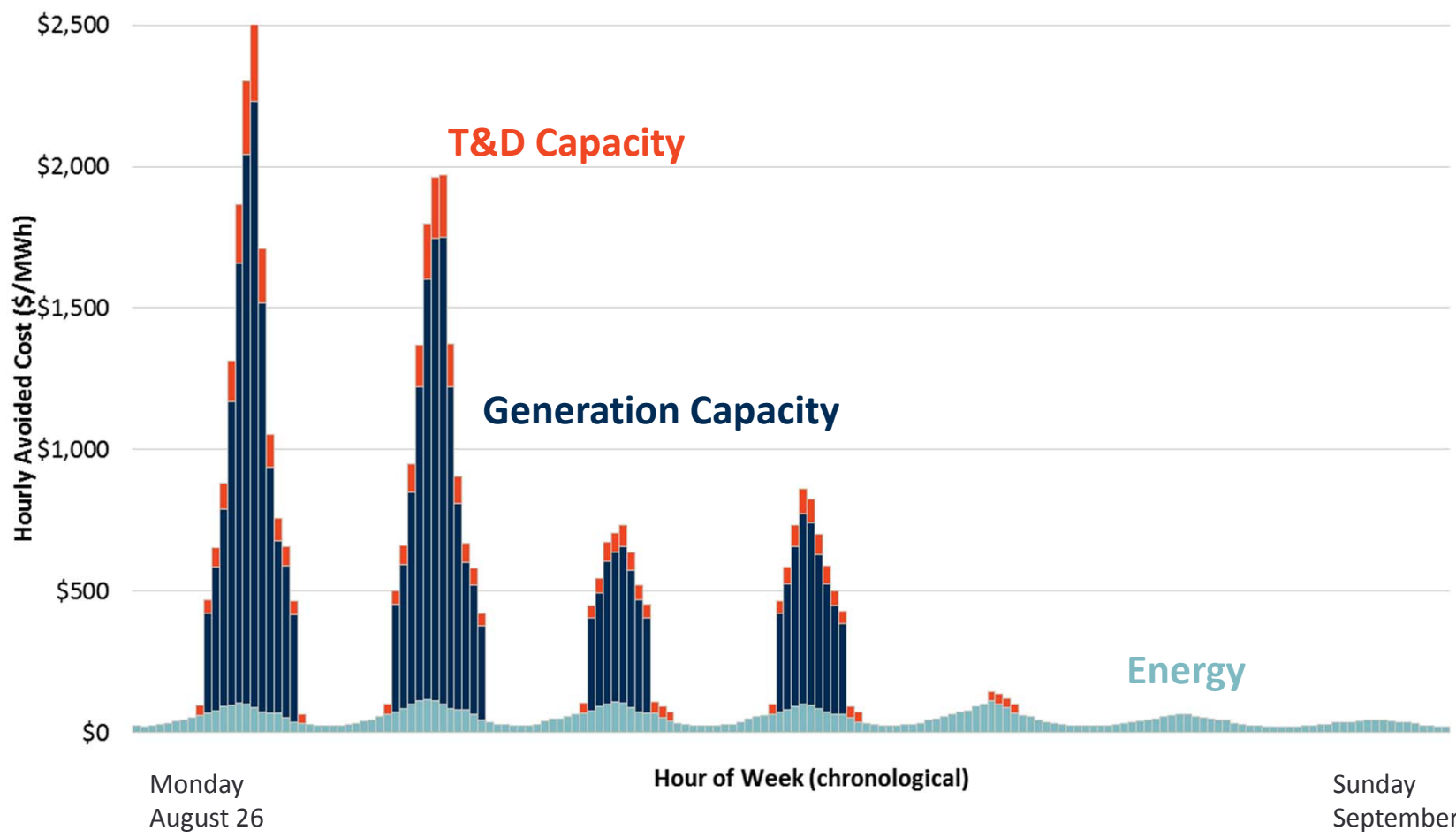
- Replacement of aging equipment
- General reliability improvements that are unrelated to peak demand
- Expansion to accommodate renewable generation

### **In Minnesota, there is no established approach to the treatment of T&D costs in DR cost-effectiveness analysis**

- Docket No. E999/CIP-16-541 established a marginal (i.e., avoidable) T&D capacity cost of approximately \$11/kW-year for NSP's energy efficiency programs
- We have adopted this as the base case marginal T&D capacity cost for DR
- In our analysis, the \$11/kW-year is allocated across hours of the year in a manner similar to generation capacity, but spread over twice as many hours to account for the lack of coincidence between the overall system peak and the T&D peaks

# DR is “dispatched” against the resulting hourly generation cost profile (energy + capacity + T&D)

**Chronological Allocation of Marginal Costs (Illustration for Week of August 26)**



## Our methodology allows for robust representation of uncertainty in key variables

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### We first assess cost-effectiveness through “deterministic analysis”

- This is the standard industry approach
- The approach produces a point-estimate of cost-effective DR potential
- It is based on “most likely” (i.e., Base Case) values for each key variable
- However, it does not account for uncertainty in the key assumptions

### We then assess cost-effectiveness through “probabilistic analysis”

- This is also known as “Monte Carlo analysis”
- It accounts for the range of uncertainty in the key variables
- A probability distribution is assigned to each uncertain variable
- Each probability distribution has an associated minimum, maximum, and most likely value based on historical data, experience from other jurisdictions, and/or our expert judgment
- A value is randomly drawn from each distribution and cost-effectiveness is estimated using those randomly selected values
- This process is repeated 2,000 times to establish a distribution of possible outcomes around the amount of cost-effective DR potential

## Other key assumptions in the analysis

### Avoided generation capacity cost

- \$57/kW-year: This is the 2023 CT cost from NSP's IRP (\$69/kW-year) adjusted downward to account for energy profit margins that the unit would earn (\$12/kW-yr)
- Lower-bound of probabilistic analysis = \$8/kW-yr, based on recent MISO capacity prices
- Upper-bound = \$79/kW-year, based on MISO Net Cost of New Entry assumptions for CTs

### Avoided T&D cost

- Base = \$11/kW-yr, from 2017 EE Avoided T&D Cost Study (Discrete Method)
- Lower-bound = \$0
- Upper-bound = \$42/kW-year, the 2023 value from Xcel's 2016 filing for the 2017-19 Conservation Improvement Program filing (Docket No. 16-115)
- Note: The upper-bound reflects a value observed in some other jurisdictions. T&D costs are highly system-specific, therefore it does not directly reflect NSP's costs. The value is simply included to establish an upper-bound on the range of costs that may generally be avoided through system-wide reductions in demand through DR programs.

### Avoided energy costs

- Based on 2013 MISO hourly day-ahead LMPs for Minnesota hub

### DR program operational constraints

- Air-conditioning DLC: 15 interruptions per summer, 2 pm to 7 pm
- Other programs: 80-100 hours of interruption, minimum 1 hour duration per interruption (note: assumed interruptions are significantly more frequent than current operation of the programs)

### Relevant programs

- The analysis is limited to non-pricing programs (DLC, interruptible tariffs, demand bidding)
- These are the programs that were included in the "DR supply curves" created in the 2014 study

# Our Assessment of NSP's Cost-Effective DR Potential

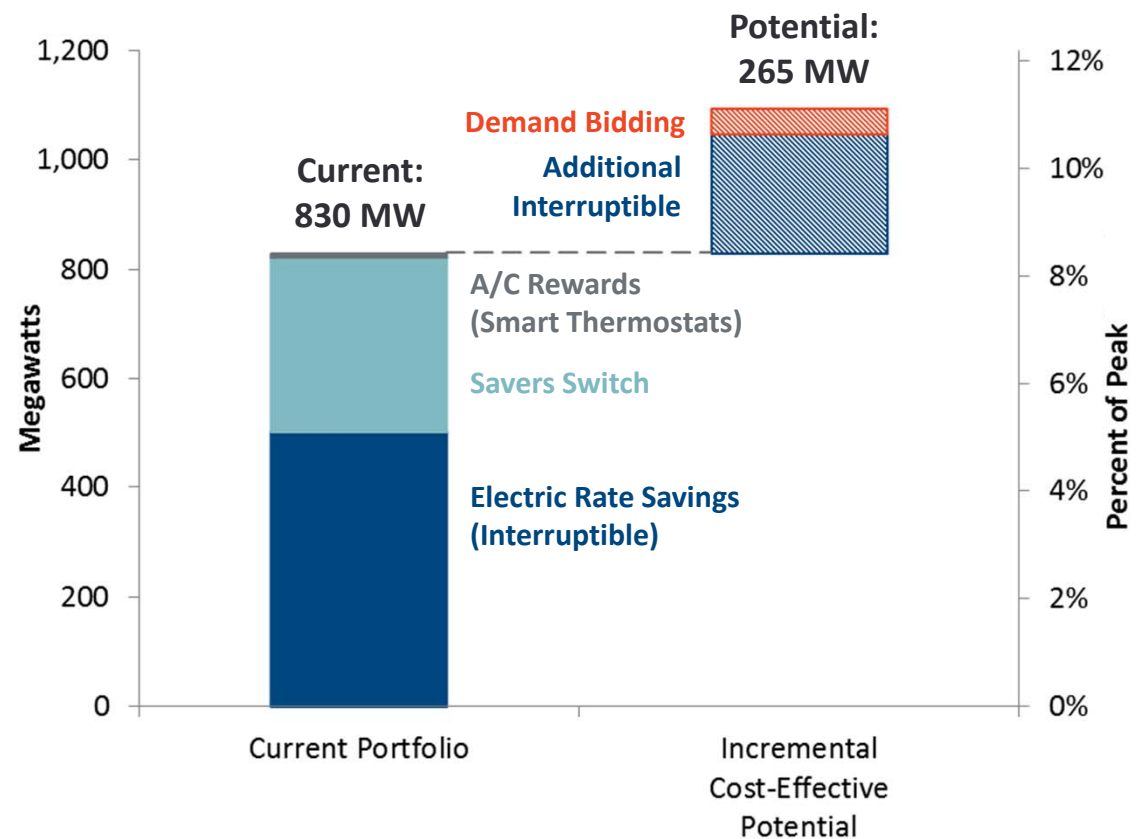
## Results of Deterministic Analysis

# In the Base Case, we estimate 265 MW of cost-effective potential for new DR programs

### Comments

- Incremental potential resides primarily in an expansion of the interruptible tariff offering for medium C&I customers
- There is modest incremental potential in the introduction of a new demand bidding program, though given the small size of the potential it is worth considering if those resources would be better spent on other new initiatives
- Incremental growth in conventional air-conditioning DLC programs is not found to be cost-effective
- Note: We have only assessed the DR potential that is incremental to existing programs; we have not analysed the cost-effectiveness of existing programs

### Existing DR Capability and Cost-Effective Potential



Notes: Potential shown for 2023. Projected 2023 peak load of 9,848 MW was used as basis for estimating % of peak impact. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017.

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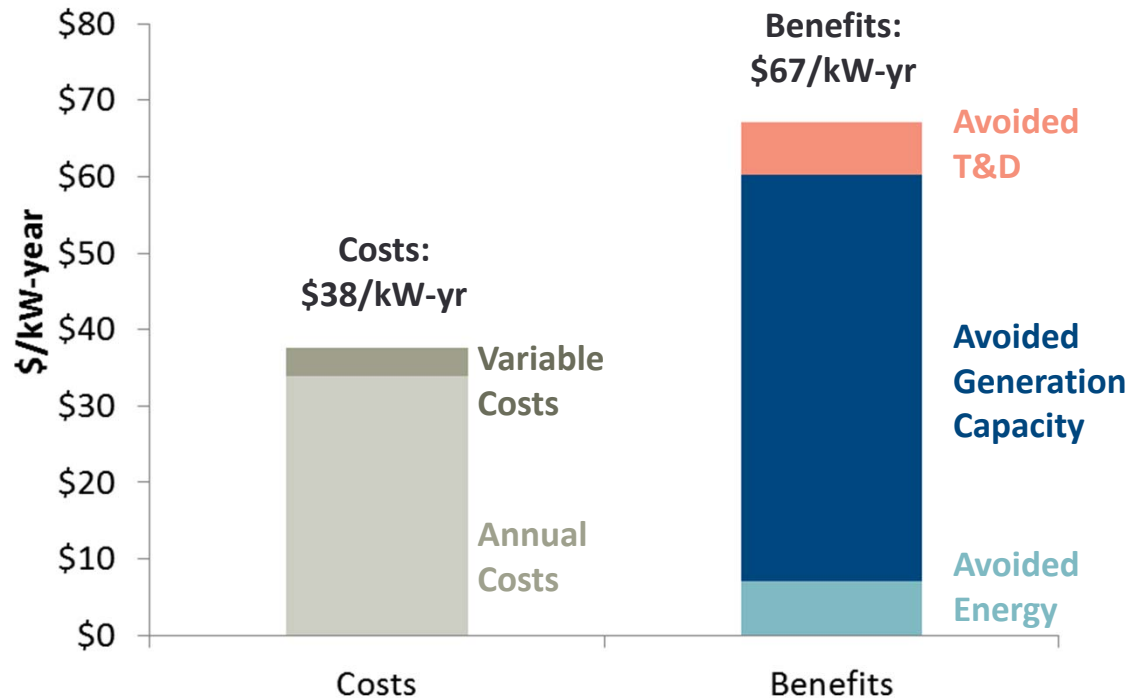
Results of Deterministic Analysis

# The benefits of DR are largely avoided generation capacity costs

## Comments

- The benefit-cost ratio of the portfolio of incremental cost-effective DR programs is 1.8-to-1
- Avoided generation capacity costs account for 80% of the total benefits
- The vast majority of costs are annual costs associated with participation incentive payments, program administration, and marketing/recruitment

## Total Costs and Benefits of all Identified Cost-Effective Incremental DR Potential



Note: Benefits and costs are shown only for those individual DR measures with a benefit-cost ratio greater than 1.0.

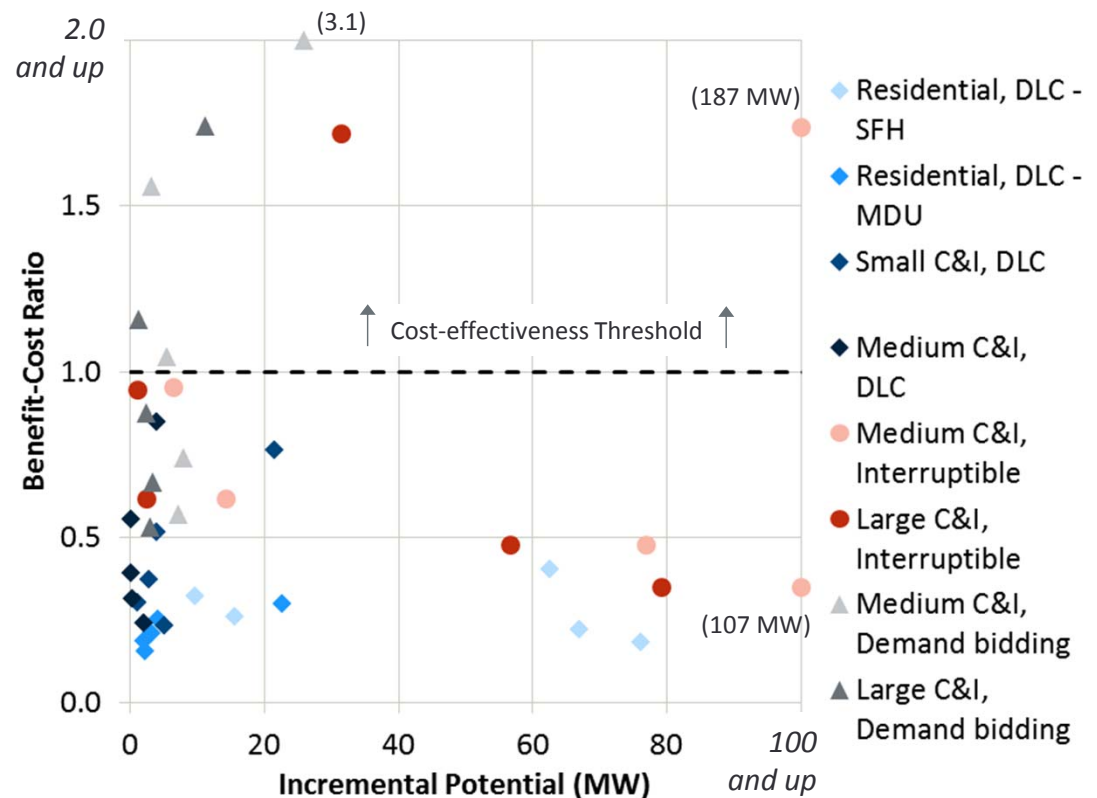
Results of Deterministic Analysis

# Only a few of the analyzed programs are cost-effective

## Comments

- In the chart at right, each data point represents a single incentive payment level associated with one DR program for one customer class (a range of incentive payment levels were analyzed in the 2014 Potential Study)
- Under Base Case assumptions, the most cost-effective program is Medium C&I Demand Bidding at the lowest incentive payment threshold, though the MW potential associated with this program is small
- Expanded Interruptible Tariffs have significantly more incremental cost-effective potential, particularly for Medium C&I customers, with benefit-cost ratios around 1.5

## B-C Ratio and Incremental Potential of Each DR Program



Note: Each data point represents a single incentive payment level for one DR program and one customer class.

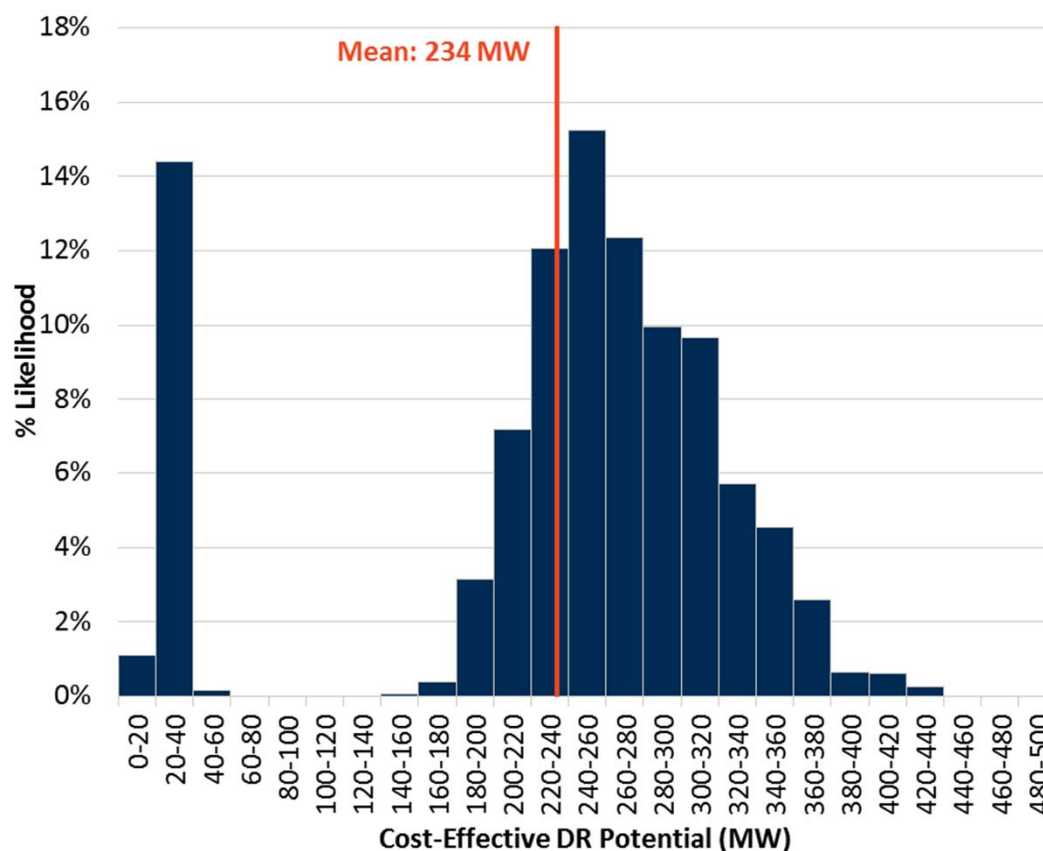
Results of Probabilistic Analysis

# Accounting for uncertainty in avoided cost estimates produces consistent findings

## Comments

- There is a 75% chance that cost-effective DR potential is less than 300 MW
- Whether the potential is less than 50 MW or in excess of 160 MW depends largely on whether or not the Medium C&I Interruptible Tariff program is cost-effective
- It is highly unlikely that the cost-effective potential in the programs analyzed in the 2014 Potential Study exceeds 350 MW

## DR Potential Probability Distribution



Note: See Appendix B for details about the assumed range of each uncertain variable in the analysis.

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## Summary of findings

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- NSP has already established a large portfolio of mature DR programs, which means that there are limited opportunities for incremental cost-effective growth in traditional DR
- NSP's incremental cost-effective DR potential is most likely between 200 and 300 MW
- The ability to efficiently enroll medium-sized C&I customers in an expanded Interruptible Tariff program is a key factor determining the amount of DR that is cost-effective
- This cost-effective potential of the programs analyzed in the 2014 Potential Study is less than the 400 MW to 1,000 MW target established by the PUC
- Further, there are likely to be operational challenges in achieving system peak demand reductions that are significantly beyond the capabilities of the current portfolio (i.e., an infeasible number of DR events to be called)
- Rather than pursuing a significant amount of traditional, peak demand-focused DR, there may be greater opportunities in alternative “flexible load” programs

# Moving Forward with DR in Minnesota – Initial Thoughts

## The cost-effectiveness findings in this presentation are not the end of the story

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**In spite of the limited amount of traditional incremental cost-effective DR identified in this study, there may be more value in alternative forms of demand flexibility**

### **Renewables integration presents one such opportunity**

- Minnesota has a goal of integrating 40%+ renewables
- This will require more than simple peak load reductions – it will require availability during non-peak hours, fast response times, and the ability to ramp quickly
- DR and other behind-the-meter options have the potential to provide these services

### **Avoided distribution costs are another emerging opportunity for DR**

- There is growing interest in the use of demand-side resources to address very location-specific constraints on the distribution system
- If adequate enrollment can be achieved, it may be possible to defer the need for upgrades in locations where capacity constraints are a near-term concern
- This concept is largely in the trial phase and requires a novel approach to DR deployment and evaluation; however it is worth consideration in future DR studies

## NSP's next DR potential study will include an expanded definition of DR

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**Which “demand flexibility” options are of interest to stakeholders?**

**An expanded definition of demand flexibility could possibly include:**

- ❑ Distributed battery storage
- ❑ Thermal storage (incl. grid-integrated water heaters)
- ❑ EV charging control
- ❑ Some types of energy efficiency
- ❑ Bring-your-own-thermostat (BYOT) programs
- ❑ Behavioral DR
- ❑ AMI-enabled dynamic pricing

# Appendix A: Details of DR Benchmarking Analysis

## Description of National DR Data

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**We analyzed two national DR datasets: FERC’s surveys of utilities in its *Assessment of DR and Advanced Metering Staff Reports (2006–2012)* and EIA-861 Demand Response data files (2006–2015)**

- In 2006–2012, FERC surveyed utilities every two years on their individual DR programs to inform its annual *Staff Report*
- The EIA has conducted the survey for many years , but annually and on aggregate DR portfolios
- Both datasets survey IOUs, munis, coops, and other load-serving entities. Shared data fields include annual capability and actual peak reduction from DR, number of customers enrolled, maximum demand from DR customers, and program costs
- To analyze DR capability as % of peak load, we also compiled peak load data reported in the EIA-861 data files

## Description of National DR Data (cont.)

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**The FERC and EIA datasets provide information on DR penetration across utilities nationwide, but there are limitations:**

- In our experience, these types of national datasets can have some reporting errors and inconsistencies
- We found the FERC survey data to more accurately represent utility DR capabilities (including NSP's) so we chose to benchmark using the latest FERC survey data available (2012)
- The % of peak metric is based on a single year of reported actual peak load
  - To the extent utilities do not adjust DR MW estimates with load, resulting % may appear high in a low load year, and low in a high load year

## Peer Group Selection Criteria

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**We selected a subset of similarly situated utilities to compare NSP's DR portfolio to those of its peer group**

### **MISO peer group represents large IOUs in nearby states**

- Neighboring states in the Upper Midwest (MN, WI, IA, MI)
- Investor-owned utilities
- Peak demand greater than 1,000 MW

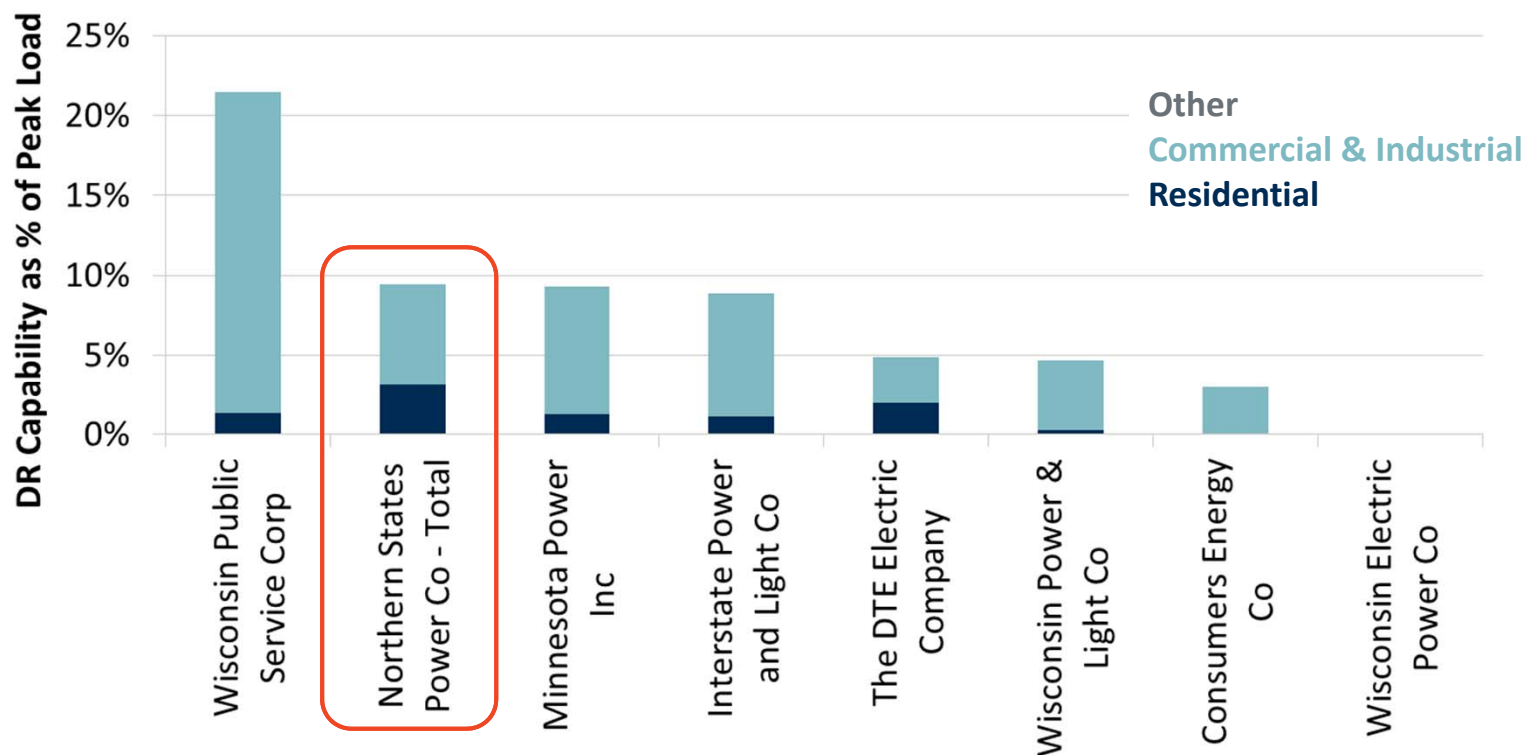
### **Other RTO peer group represents large IOUs with comparable peak load and serving major cities**

- RTOs with capacity market (NYISO, PJM, ISO-NE)
- Investor-owned utilities serving major cities
- Peak demand greater than 5,000 MW

# NSP Compared to MISO Peer Group

**NSP ranks highly among MISO IOUs in total and residential DR capability.**

- NSP has the most “nameplate” DR capability (830 MW) of all MISO IOUs, and ~300 MW beyond that of the next closest IOU (DTE: 550 MW, WPSC: 500 MW).
- WPSC has a larger portfolio as a % of peak demand, though lower enrollment as a % of its total customer base due to a portfolio predominantly composed of C&I

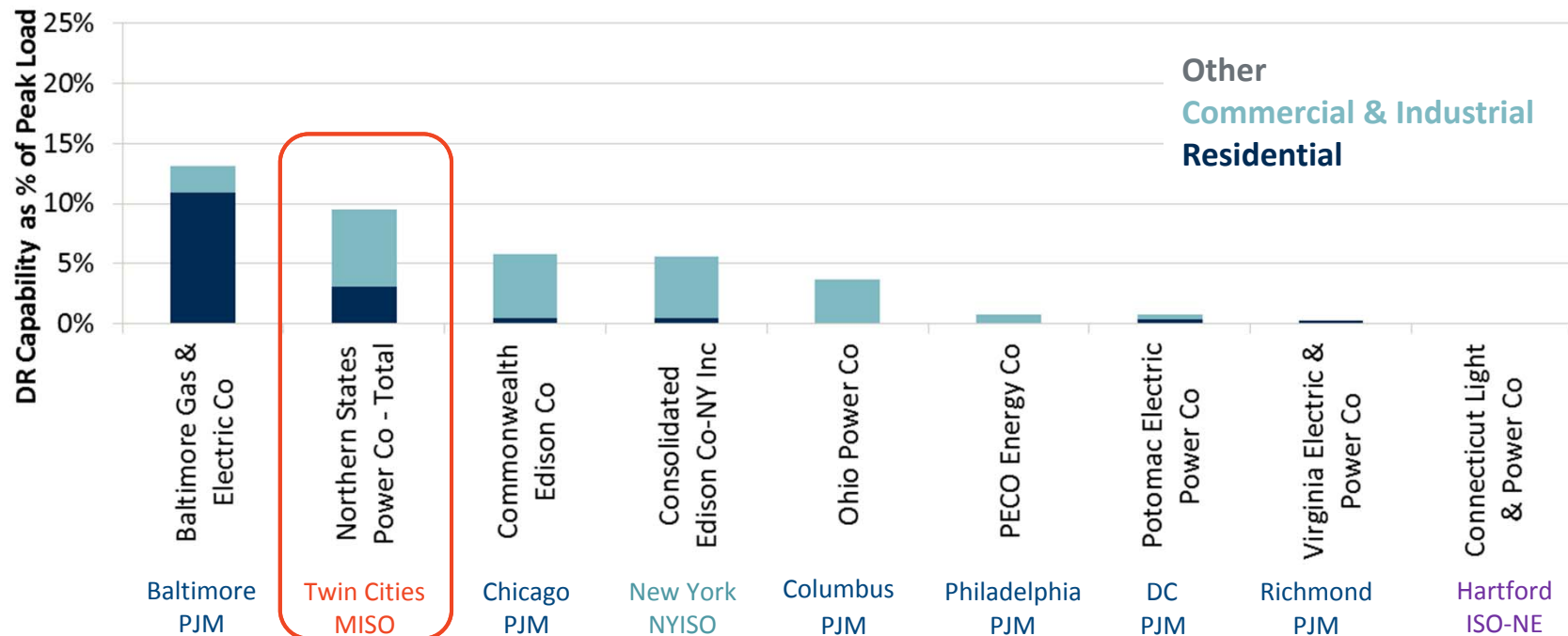


Sources and Notes: FERC, 2012 Assessment of Demand Response and Advanced Metering and EIA 861 peak load data. Excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP’s capability calculated as current portfolio divided by 2016 peak load.

# NSP Compared to Other RTO Peer Group

## NSP compares favorably to large IOUs in markets with more lucrative DR products (PJM and NYISO)

- BG&E (920 MW) and ComEd (1,360 MW) are the only other IOUs in peer group with comparable total MW DR capability. Outside of peer group, NSP ranks **8<sup>th</sup>** nationally in total DR capability, and **11<sup>th</sup>** nationally in DR capability as share of peak.



Sources and Notes: FERC, 2012 Assessment of Demand Response and Advanced Metering and EIA 861 peak load data. Excludes peak reduction capability from time-of-use programs because these loads are not controllable. Share in residential DR does not control for differences in overall load composition. For example, BG&E total energy sales were 75% residential compared to NSP energy sales which were only 29% residential. NSP's capability calculated as current portfolio divided by 2016 peak load.

# NSP's existing DR portfolio ranks highly against those of other large IOUs

## NSP DR Capability Compared to IOU Peer Group 2012 FERC Survey

	RTO	State	Peak Load (MW)	DR Peak Reduction Capability				Share of DR MW		Customers Enrolled in DR	
				Total DR (MW)	Res. (MW)	C&I (MW)	Total DR (% of peak)	Res. (%)	C&I (%)	Res. (customers)	Total (customers)
Northern States Power Co - Total	MISO	MN	8,774	830	270	560	9%	33%	67%	446,808	467,161
Wisconsin Public Service Corp	MISO	WI	2,347	504	32	473	21%	6%	94%	25,375	25,861
Minnesota Power Inc	MISO	MN	1,633	152	20	132	9%	13%	87%	7,217	7,761
Interstate Power and Light Co	MISO	IA	3,130	279	34	245	9%	12%	88%	48,928	49,115
The DTE Electric Company	MISO	MI	11,182	547	219	328	5%	40%	60%	281,031	281,689
Wisconsin Power & Light Co	MISO	WI	2,851	134	7	127	5%	5%	95%	10,700	10,800
Consumers Energy Co	MISO	MI	8,387	246	0	246	3%	0%	100%	0	30
Wisconsin Electric Power Co	MISO	WI	6,294	0	0	0	0%	-	-	0	152
Baltimore Gas & Electric Co	PJM	MD	7,002	919	763	157	13%	83%	17%	405,944	411,064
Commonwealth Edison Co	PJM	IL	23,601	1,357	116	1,241	6%	9%	91%	83,537	87,312
Consolidated Edison Co-NY Inc	NYISO	NY	5,492	305	23	282	6%	8%	92%	22,395	32,202
Ohio Power Co	PJM	OH	9,670	351	0	351	4%	0%	100%	0	8
PECO Energy Co	PJM	PA	8,549	64	0	64	1%	0%	100%	0	118
Potomac Electric Power Co	PJM	DC	6,674	50	25	25	1%	50%	50%	25,000	72,769
Virginia Electric & Power Co	PJM	VA	16,787	50	50	0	0%	100%	0%	28,000	28,013
Connecticut Light & Power Co	ISONE	CT	5,280	5	0	5	0%	0%	100%	0	12
All MISO IOUs in Survey Data (12 IOUs)			55,231	2,978	718	2,260	5%	24%	76%	880,849	908,232
All U.S. IOUs in Survey Data (100 IOUs)			456,353	19,942	5,289	14,273	4%	27%	72%	4,653,575	4,838,625
All Utilities in Survey Data (387 Utilities)			563,074	27,383	7,015	19,346	5%	26%	71%	5,801,247	6,025,979

*Sources and Notes:* FERC, 2012 Assessment of Demand Response and Advanced Metering and EIA 861 peak load data. Excludes utilities that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. Res. and C&I DR do not add up to Total DR for All U.S. IOUs and All Utilities because Other DR is excluded from table. NSP's capability calculated as current portfolio divided by 2016 peak load.

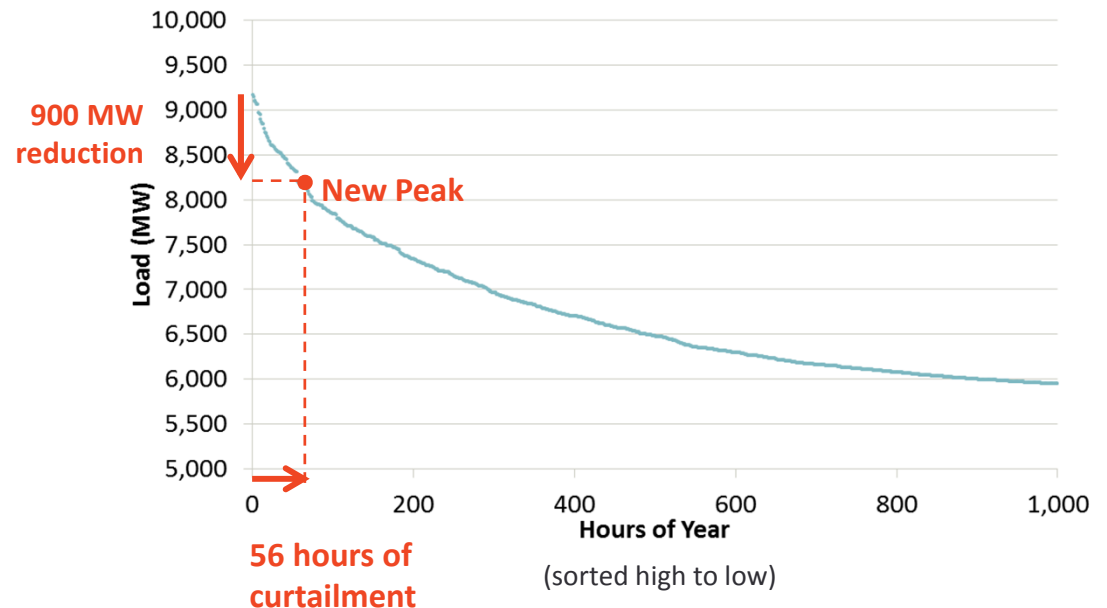
# Appendix B: Additional Considerations in Assessing DR Potential

## The operational constraints of DR programs have implications for the ability to reduce peak demand

### Comments

- Reducing system peak demand by 900 MW (roughly the size of NSP's current DR portfolio) requires load reductions in the top **56** hours of the year
- Otherwise, one of these top **56** hours will set the new peak at a level that exceeds the target
- In 2013, those top **56** hours occurred on **8** different days of the year

### NSP's 2013 Load Duration Curve



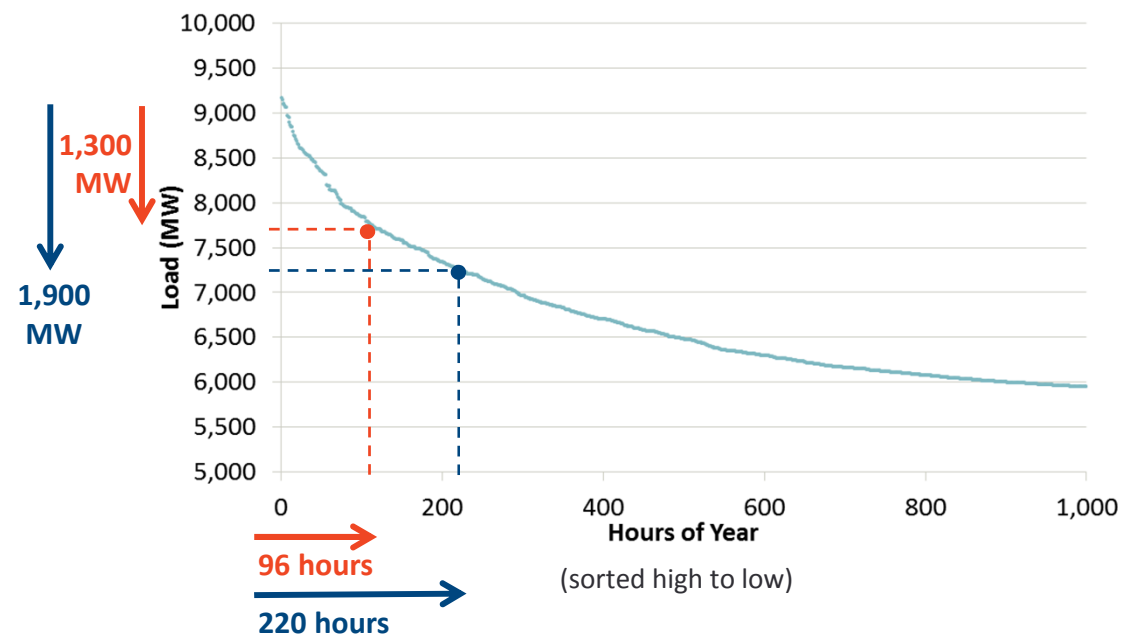
*Sources and Notes:* 2013 system load for NSP service territory, provided by Xcel. 2013 was chosen as the year for this example, because it was the year with the highest peak demand in the past several years.

# Achieving larger load reductions requires that DR be dispatched during more hours of the year

## Comments

- A **1,300 MW** reduction (the PUC’s target for NSP’s DR capability) would require that DR be dispatched during at least **96** hours of the year
- In 2013, those hours spanned **13** days of the year, **12** different hours of the day, and **5** days of the week
- DR events would need to be called on **5** consecutive days in this scenario
- Achieving a **1,900 MW** peak reduction would require that DR be utilized during **27** different days of the year
- The number and frequency of necessary interruptions is significantly higher in other recent years, when peak load was less concentrated in the top hours

## NSP’s 2013 Load Duration Curve

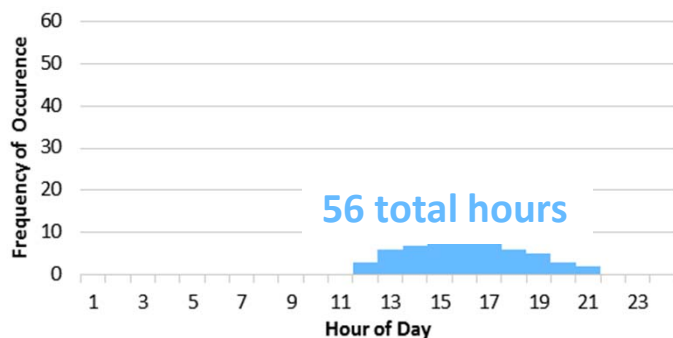


Sources and Notes: 2013 system load for NSP service territory, provided by Xcel. 2013 was chosen as the year for this example, because it was the year with the highest peak demand in the past several years. Results will vary depending on the year being analyzed.

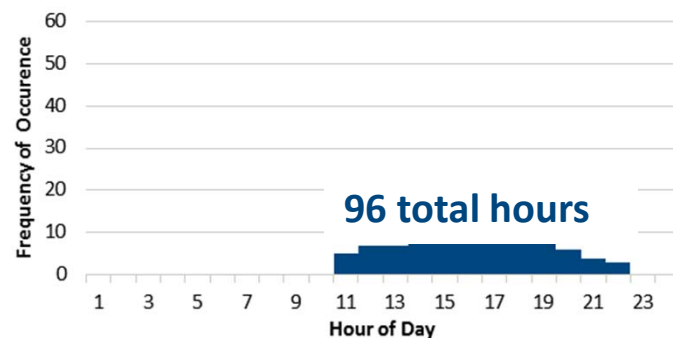
# Achieving very large peak demand reductions will likely exceed the capabilities of traditional DR

## Hours of Day When DR Would Need to be Utilized

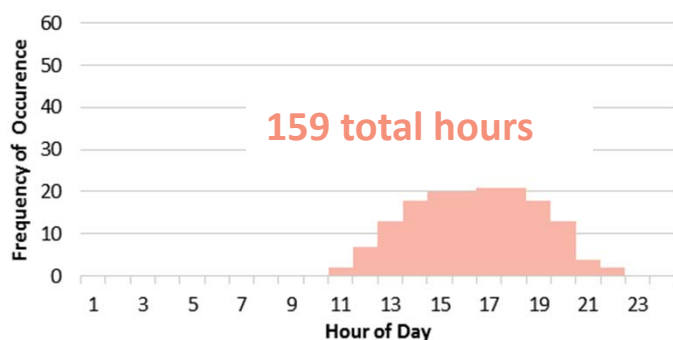
**1** 900 MW Reduction, 2013 Load



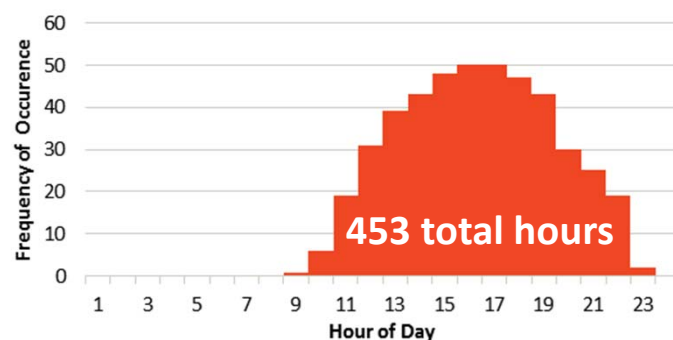
**2** 1,300 MW Reduction, 2013 Load



**3** 1,300 MW Reduction, 2015 Load



**4** 1,900 MW Reduction, 2015 Load



Note: The charts illustrate the distribution of hours when a DR event would need to be called in order to achieve the specified load reduction for the specified year's load shape.

# Appendix C: Cost-Effectiveness Analysis Assumptions

# Additional assumptions

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## Hours of generation capacity value allocation

- Base case = Top 100 load hours
- Min (probabilistic analysis) = Top 25 hours
- Max (probabilistic analysis) = Top 250 hours

## Load year

- 2013, selected because it represents the highest peak demand in recent historical data (2012 through 2015) and also has the peakiest load shape, contributing to a slightly higher value of DR than other years

## Planning reserve margin

- For the purposes of estimating avoided generation capacity costs, impacts are grossed up by the planning reserve margin
- This accounts for a reduced planning need
- NSP's planning reserve margin for its own system peak is 2.41% due to non-coincidence with the MISO peak

## Line losses

- Impacts in the 2014 Potential Study were reported at the generator level; no gross-up was needed to account for line losses

## Energy margin

- According to NSP modeling, the net energy margins (sum of marginal energy price minus the unit's variable costs over all operational hours) for a new CT in the study years is roughly between \$6 and \$18/kW-year
- We assume \$12/kW-year, the middle of this range

## Participation

- Base case impacts were based on the supply curve values produced for the 2014 Potential Study
- In an appendix to that study, we conducted a sensitivity case for each DR program's participation assumption, based on participation rates used in the 2009 FERC Assessment of DR Potential (which were based on the 75<sup>th</sup> percentile of national DR enrollment rates)
- For all but one program, the sensitivity case participation rates were lower than those used in the 2014 study
- For the probabilistic assessment in cost-effectiveness analysis, we used the absolute value of the difference between the FERC values and the 2014 Potential Study values to create upper- and lower-bound participation rates.
- The upper- and lower-bounds range anywhere from +/-5% of the Base participation rate, to +/-82%, depending on the program analyzed

## Additional methodological notes

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The scope of this study was only to assess the cost-effectiveness of the DR programs analyzed the 2014 Potential Study

We did not analyze time-varying pricing programs, since NSP has not deployed AMI

We have only assessed the DR potential that is incremental to existing programs; we have not analyzed the cost-effectiveness of NSP's existing DR portfolio

Our analysis is conducted from the standpoint of DR costs and benefits in 2023, the year by which the PUC has required NSP to add 400 MW of DR (and the year before the projected need for new peaking capacity, per the IRP)

# Appendix D: Additional Background

# NSP's DR programs

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## Savers Switch:

- Central air-conditioning DLC
- Compressor switch with 15- to 20-minute cycling
- Additional option to enroll water heater
- Residential and business customers
- Residential incentive = 15% savings on energy charges (June – Sept)
- Business incentive = \$5/ton of A/C (June – Sept)
- 321 MW of peak demand reduction capability (2016)

## A/C Rewards:

- DLC for customer-owned smart thermostats
- Temporary modification of thermostat set point
- Residential
- Incentive = \$25/yr, plus up to \$125 rebate toward purchase of select smart thermostats or \$75 payment for registering an installed smart thermostat
- 8 MW of peak demand reduction capability (2016)

## Electric Rate Savings:

- Interruptible tariff, customer must reduce load to pre-specified level
- Medium and large C&I customers
- Minimum 50 kW demand reduction for eligibility
- Control periods can occur any time of year
- Incentive = \$5.86 to \$8.44 per kW of controllable load (June-Sept), \$1.75 to \$4.33 per kW (Oct-May)
- 501 MW of peak demand reduction capability (2016)

## The 2014 DR Potential Study

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### **The purpose of the study was to:**

- Quantify the potential peak demand reduction that could be achieved through an expanded portfolio of demand response (DR) options in NSP's service territory, without cost considerations
- Identify future DR opportunities for NSP

### **We considered 22 different programmatic DR options and segmented the market into four customer classes**

- 9 of the options were existing programs and 13 were possible new options
- 10 were considered "traditional" DR options and 12 were AMI-enabled options

**We also estimated program costs which, when combined with the peak reduction estimates, produced a "supply curve" of traditional DR resources that could be used as input to NSP's integrated resource planning (IRP) process**

**Note: Our DR potential estimates did not account for the cost-effectiveness of the DR measures**

## The 2014 Potential Study (cont'd)

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The following DR options were analyzed

### Currently offered options

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch
- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate
- **Time-of-use (TOU) rates:** NSP currently offers TOU rates, which are replaced in our analysis by re-designed rates (see discussion below)

### Possible new options

- **Demand bidding:** Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty
- **Critical peak pricing (CPP) rates:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and \$1.00/kWh) during peak hours on up to 10 or 15 days per summer; can be offered with "enabling technology" which automates load reductions in response to the higher priced hours
- **Redesigned time-of-use (TOU) rates:** Existing TOU rates were redesigned to be more manageable and targeted, with a shorter peak period and a revised peak-to-off-peak price ratio