# Integrated Resource Planning: Delivering Energy Services at the Lowest Total Cost

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# Overview

- The history of Integrated Resource Planning (IRP)
- Fundamental reasons for IRP
- Key elements of IRP
- Making IRP work in a regulated utility framework
- Key questions and future directions for IRP

# History of IRP

- Developing power grids tend to promote end-use growth to realize economies of scale and universal service
  - This paradigm prevailed in the U.S. from the 1880s to about 1970
  - Load growth permitted full grid deployment and modernization, and economies of scale in generation, transmission and distribution
  - U.S. regulators mainly approved rate reductions based on economies of scale

# History of IRP

- After 1970, the U.S. paradigm shifted
  - Grid and generation economies of scale peaked
  - Fuel prices spiked
  - Capital costs rose (especially for nuclear)
  - Environmental costs began to be reckoned
- The resulting rate shocks changed policies
  - The federal Public Utility Regulatory Practices Act (PURPA)
  - State utility commission planning, ratemaking, and other practices

# History of IRP

- During the 1970s, the concept of "least-cost energy services" emerged
  - Energy services are not commodities like oil, but services like comfort, lighting, shaft power, computing
  - Efficiency technologies provide energy services with less energy commodity, and at lower cost
  - Least-cost energy services are the mix of energy commodities and end-use efficiency technologies that provide the lowest total cost to the customer

# History of IRP

- Many state PUCs during the 1980s turned the concept of least-cost energy services into Least-Cost Planning, which morphed into Integrated Resource Planning
  - The concept of Demand-Side Management (DSM) emerged alongside IRP to provide a framework for identifying resources on the demand side of the meter
  - DSM may include energy efficiency (EE), load management/demand response (DR), plus rate designs that encourage either or both.

# Fundamental IRP Rationale

- Ensure generation is available to meet demand, and vice versa
- Minimize total system costs
- Minimize total customer energy bills
- Enhance reliability
- Reduce environmental costs

# Key elements of IRP

- Define IRP process: objectives, planning period, analytical methods, public participation
- Forecast demand for the planning period
- Identify resource options—supply and demand
- Optimize resource mix to meet IRP objectives
- Develop long-term resource plan (e.g. 10-15 years) and short-term action plan (e.g. 1-5 years)
- Acquire resources/implement programs
- Evaluate to inform subsequent planning cycles

# Load Forecasting

- Trend extrapolation no longer sufficient
- Combine top-down (e.g. econometrics) with bottom up (e.g. technology and market) analyses
- Typically apply a mix of
  - Economic activity forecasts
  - Building construction forecasts
  - Appliance/equipment stock turnover
  - Effects of efficiency standards and building codes
- Develop high-mid-low scenarios, with sensitivity analyses

# Resource Options

- Supply side
  - Conventional plants--fossil-fueled, nuclear, combustion turbines, life extensions, transmission/distribution expansion or upgrade (including loss reductions)
  - Non-utility owned generation—CHP, IPPs
  - Bulk Power Purchases
  - Renewables—wind, geothermal, biomass, solar

# Resource Options

- Demand-Side
  - Energy efficiency incentive/information programs
    - Residential mass market lighting and appliances
    - Residential HVAC replacement
    - Residential new construction
    - Residential retrofits
    - Commercial/Industrial lighting, equipment, HVAC
    - Customized programs for larger customers
  - Demand response incentive/enabling programs
  - Pricing—interruptible, time of use pricing, real time pricing

# Optimize Resource Mix

- Estimate relative scale of available resources
- Project resource costs
- Conduct cost-effectiveness analysis
  - Requires determination of avoided costs and other key variables
  - Determine cost-effectiveness tests to be applied
- Conduct uncertainty/risk analysis
- Consider reliability issues
- Consider “loading order”—require least-cost resources to be acquired first

# Making IRP Work for Regulated Investor-Owned Utilities

- Potential negative financial impacts of DSM
- Addressing negative impacts through ratemaking and related practices
  - Cost Recovery
  - Revenue stability
  - Shareholder incentives

# Potential Negative Impacts of DSM on Utility Finances

- Most U.S. states use "volumetric" ratemaking (costs allocated by volume of energy sales):
  1. Calculate revenue requirements, based on
     a. fixed costs,
     b. variable costs, and
     c. allowed rate of return
  2. Forecast energy sales for one or more years
  3. Divide revenue requirements by forecast sales to produce an averaged rate

*(This is highly oversimplified!)*

# Potential Negative Impacts of DSM on Utility Finances

- Volumetric ratemaking has the virtue of encouraging customers to limit energy use
- *But*: traditional ratemaking creates a disincentive for the utility to reduce energy sales
  - Each “lost” unit of energy sales carries with it a part of the company’s fixed costs
  - Small changes in energy sales can have major effects on fixed cost recovery and effective return on equity

# Small Sales Variations Have Big Impacts on Earnings

| | Revenue Change | | Impact on Earnings | | |
|---|---|---|---|---|---|
| % Change in Sales | Pre-tax | After-tax | Net Earnings | % Change | Actual ROE |
| 5.00% | $9,047,538 | $5,880,900 | $15,780,900 | **59.40%** | 17.53% |
| 4.00% | $7,238,031 | $4,704,720 | $14,604,720 | **47.52%** | 16.23% |
| 3.00% | $5,428,523 | $3,528,540 | $13,428,540 | **35.64%** | 14.92% |
| 2.00% | $3,619,015 | $2,352,360 | $12,252,360 | **23.76%** | 13.61% |
| 1.00% | $1,809,508 | $1,176,180 | $11,076,180 | **11.88%** | 12.31% |
| 0.00% | $0 | $0 | $9,900,000 | **0.00%** | 11.00% |
| -1.00% | -$1,809,508 | -$1,176,180 | $8,723,820 | **-11.88%** | 9.69% |
| -2.00% | -$3,619,015 | -$2,352,360 | $7,547,640 | **-23.76%** | 8.39% |
| -3.00% | -$5,428,523 | -$3,528,540 | $6,371,460 | **-35.64%** | 7.08% |
| -4.00% | -$7,238,031 | -$4,704,720 | $5,195,280 | **-47.52%** | 5.77% |
| -5.00% | -$9,047,538 | -$5,880,900 | $4,019,100 | **-59.40%** | 4.47% |

Source: Regulatory Assistance Project

# Energy Sales are No Longer Rising Consistently

- U.S. gas utilities have seen declining average sales per customer for ~20 years
- Electricity sales still rising in some regions, but growth rate is slowing
  - 1950s: growth rates ~10%
  - 1970s: growth rates ~4%
  - Current national forecast: ~1%
  - Some states (VT) showing negative growth
- Energy efficiency policies and programs slowing or reducing energy sales in many states

# How Do Regulators Address Fixed-Cost Recovery?

- Business-as-usual: period rate cases reset revenue requirements, forecasts, rates
  - This worked for decades, when economies of scale typically drove down average rates
  - Variations from allowed ROE are "trued-up", but on a longer cycle than decoupling, so rate adjustments can be large
  - *But:* utilities can happily over-earn for years
  - *And:* rising sales drives need for new assets, which increases ratebase, and increases total earnings
  - So: utilities' incentive is to drive up sales, and to not let sales fall below forecast levels

# How Do Regulators Address Fixed-Cost Recovery?

- Lost Revenue Adjustments
  - Estimate revenue losses from efficiency programs
  - Create a mechanism to recover “lost revenues”
  - *But:*
    - Creates controversial situations re measurement and verification
    - If sales were already above forecast, were sales really “lost” since earnings would have been above allowed level?
    - Doesn’t change the basic throughput incentive to increase sales

# How Do Regulators Address Fixed-Cost Recovery?

- Straight Fixed-Variable (SFV) Rates
  - Fully separate all fixed costs, and place in fixed charges on a per-customer basis
  - Volumetric element of rates based only on variable costs (generation fuel, etc.)
  - *But:*
    - Customer conservation incentive is reduced—lengthens payback periods for efficiency investments
    - Lower-use customers see proportionately larger rate increases
    - Raises equity issues between customer classes

# SFV Worsens Efficiency Economics

**Reduction of Monthly Customer Usage from 1,000 to 900 kWh**
**Energy Efficiency Investment of $200**

| | **Standard Tariff**<br>Fixed charge $15.00<br>$0.075/kWh | **Straight Fixed Variable Tariff**<br>Fixed charge $50.00<br>$0.04/kWh |
|---|---|---|
| **1,000 kWh** | Fixed charge $15.00<br>Volumetric charge $75.00<br>Total $90.00 | Fixed charge $50.00<br>Volumetric charge $40.00<br>Total $90.00 |
| **900 kWh** | Fixed charge $15.00<br>Volumetric charge $67.50<br>Total $82.50 | Fixed charge $50.00<br>Volumetric charge $36.00<br>Total $86.00 |
| **Savings** | $7.50/month ($90/year) | $4.00/month ($48/year) |
| **Payback period** | 2.2 years | 4.2 years |

Source: Regulatory Assistance Project

# Revenue Decoupling

- Creates a mechanism to recover revenues at allowed levels, separate from energy sales levels
- “Trues-up” rates on pre-set formula, typically annually
- Can be structured in various degrees
  - Full decoupling—correct for any deviation from forecast, applies to all customers
  - Partial decoupling—corrects only for specified factors (weather, economic conditions), or applies only to specific customer classes
  - Efficiency-only decoupling—corrects only for program impacts

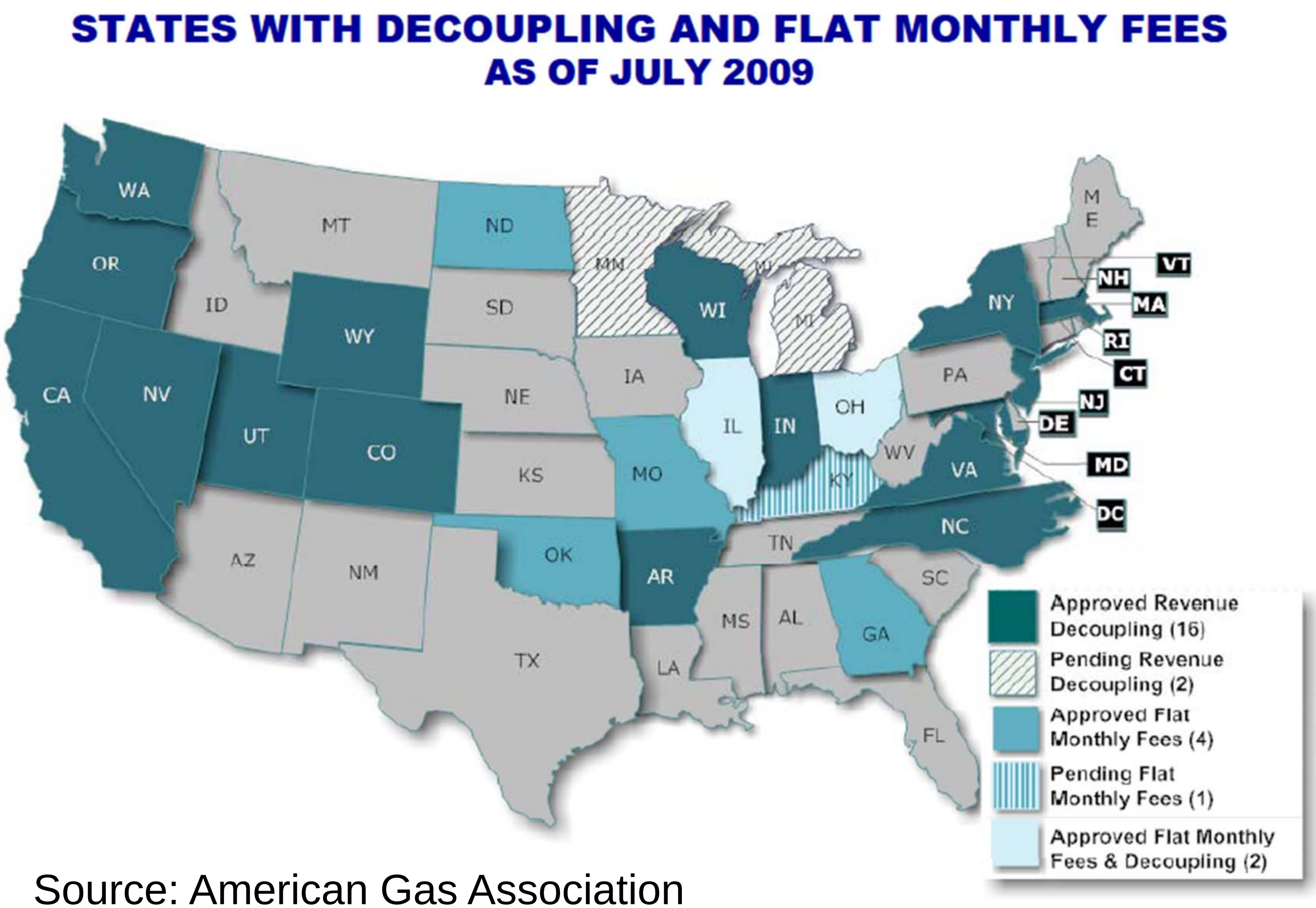
# Basic Decoupling Process

- Utility “base” revenue requirement determined with traditional rate case
  - Detailed review of costs, forecasts
- Each future period assigned “allowed” revenue requirement
- Differences between allowed/actual revenues are tracked
- Revenue difference (positive or negative) is captured in a small adjustment to rates

# Key Issues in Decoupling Design

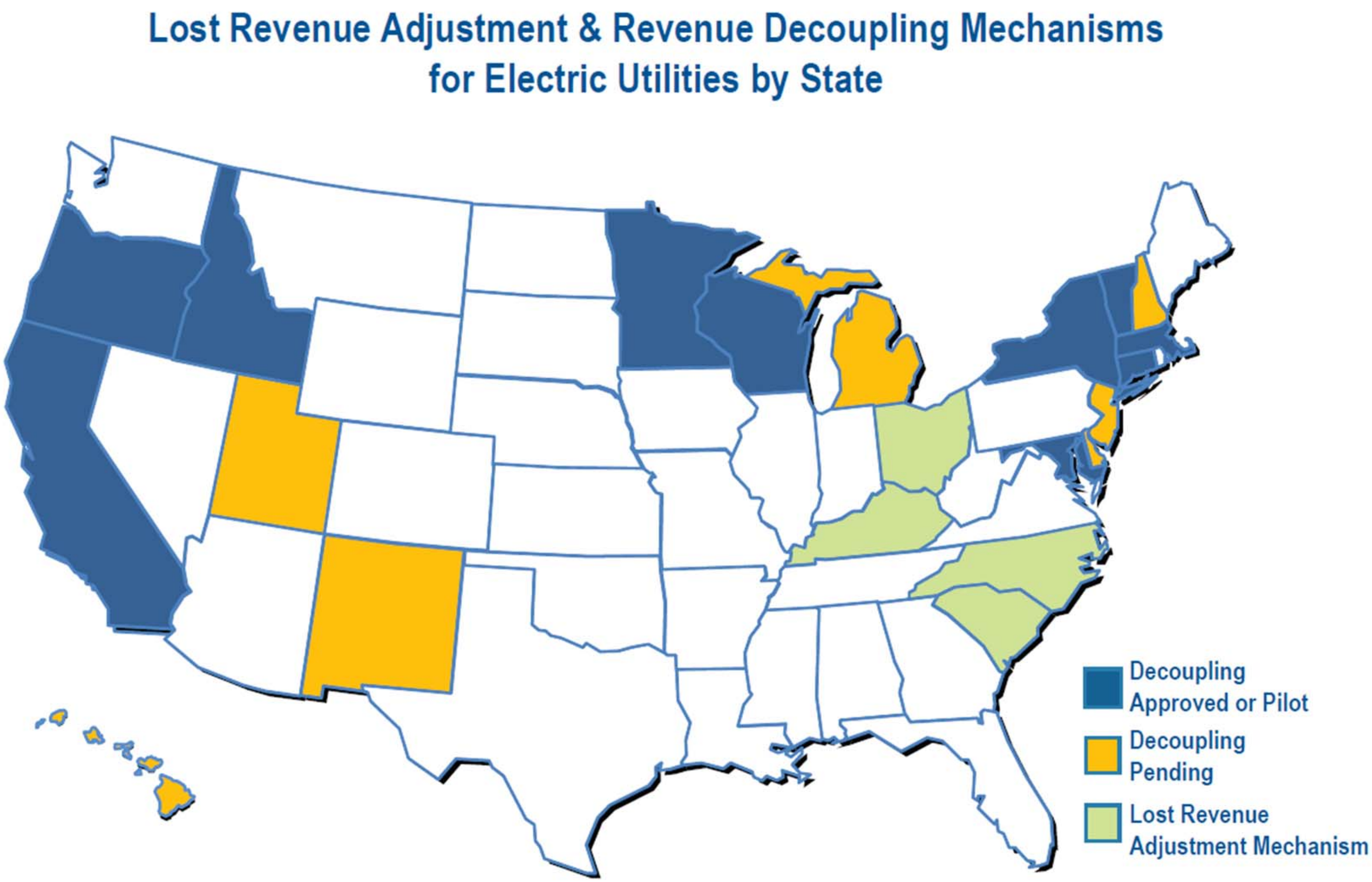
- Adjustment to utility's return on equity
  - Reduction in revenue risk may warrant this
  - Can reduce utility's cost of capital, which can moderate costs and rates overall
- Formula for revenue recovery adjustment
  - Total revenue vs. revenue per customer
  - Full or partial decoupling
  - True-up interval and related accounting details
  - Caps/floors to adjustments
    - Maximum changes in rates/minimum sales variations ("Dead bands")

# States Pursuing Decoupling (Gas)




Source: American Gas Association

# States Pursuing Decoupling (Electric)

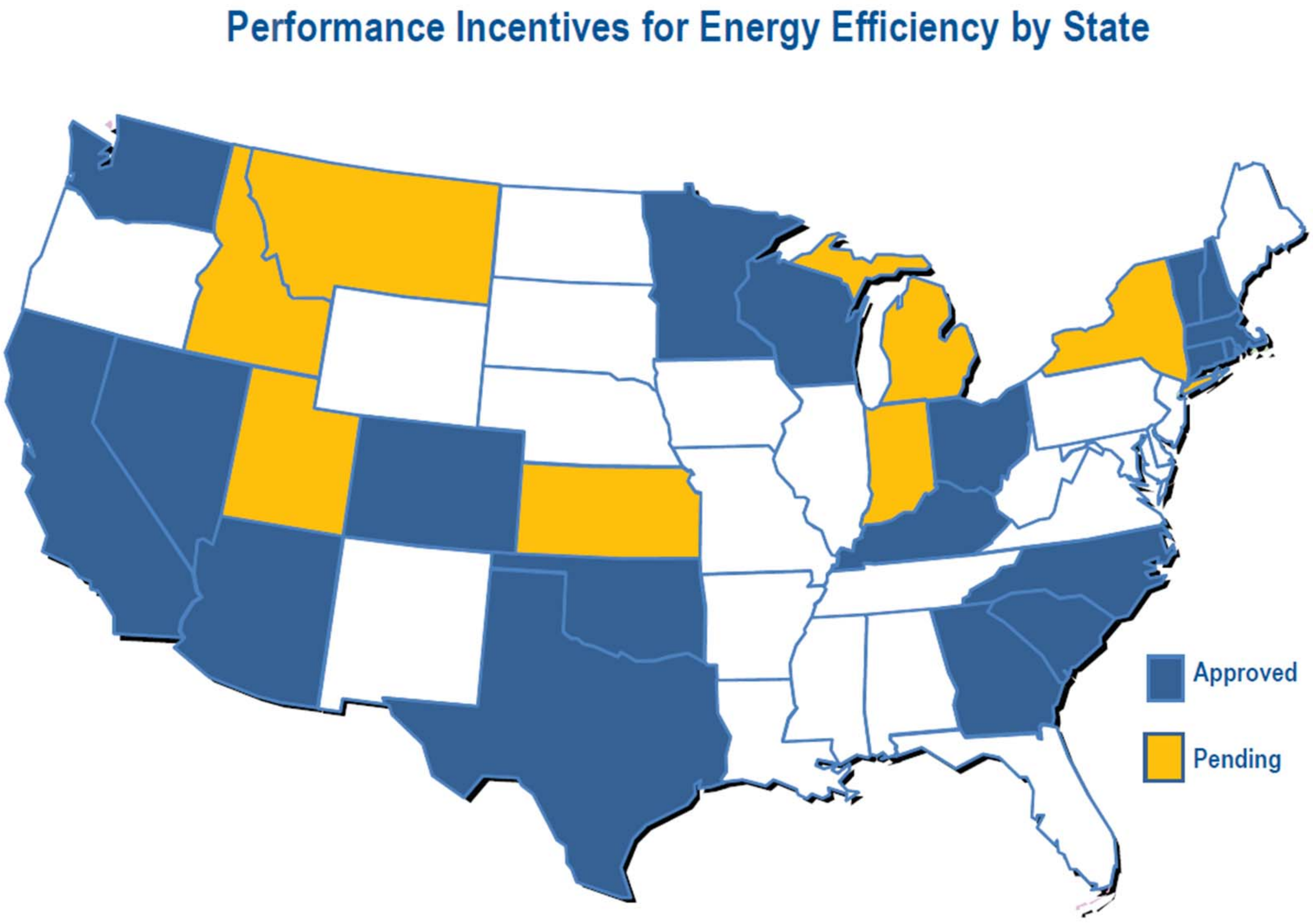



Source: Institute for Electric Efficiency

# Decoupling is Not Enough

- Removes disincentive by stabilizing revenues
- But decoupling does not create positive earnings potential for investments in customer efficiency
- Many states have created earnings incentives:
  - Shared savings—utility earns % of avoided costs, of net energy savings
  - Performance targets—Specified rewards (e.g., % of EE budget) for achieving defined targets (e.g. energy savings)
  - ROE adder—a premium on the rate of return on allowed EE program costs

# Electric Utility Incentives



# Key Questions

- How does IRP apply in restructured electricity markets?
  - Value streams are fragmented
  - Regulatory jurisdictions are segmented
  - Analytical methods are complicated (e.g. avoided costs)
- How does smart grid technology affect IRP?
  - For larger customers, aspects of IRP can be managed in real time
  - Will all customer classes ultimately have such choices?

# Future Directions

- IRP requires integrated market structures and regulatory structures
  - Unclear how this will unfold in the U.S.
  - Organized wholesale market states/regions different from traditional vertically integrated regions/states
- Distributed generation/microgrid technologies, combined with smart grid utility technologies, could create a much more complex and adaptive power sector

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