From DSR to aggregated response

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June 23rd, 2016

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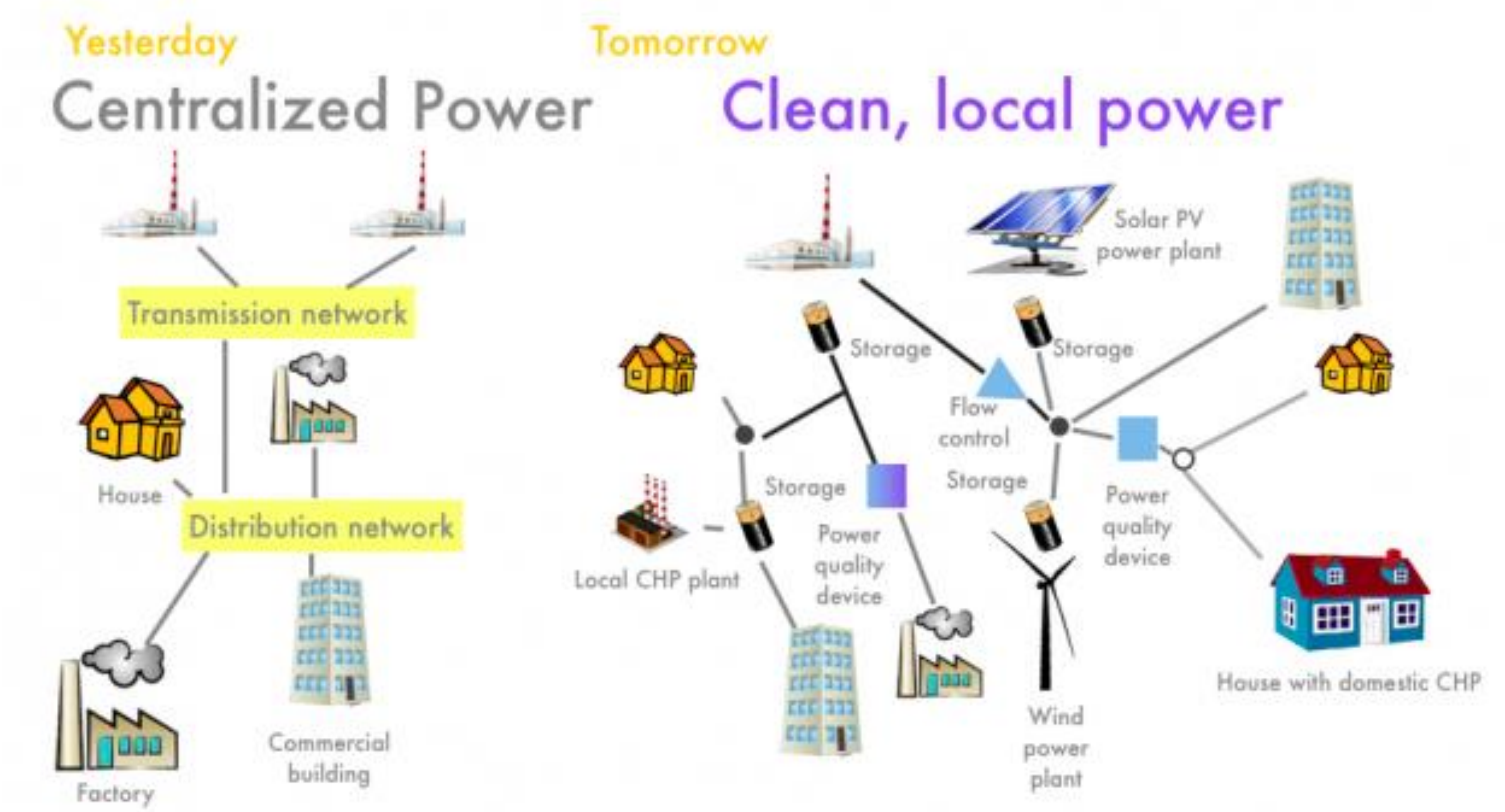
Smart Grid Paradigm Shift



"Smart Grids are electricity networks that can intelligently integrate the behavior and actions of **all users** connected to it generators, consumers, and those that do both in order to efficiently deliver <u>sustainable</u>, <u>economic</u> and <u>secure</u> electricity supplies (ETP, 2011)"

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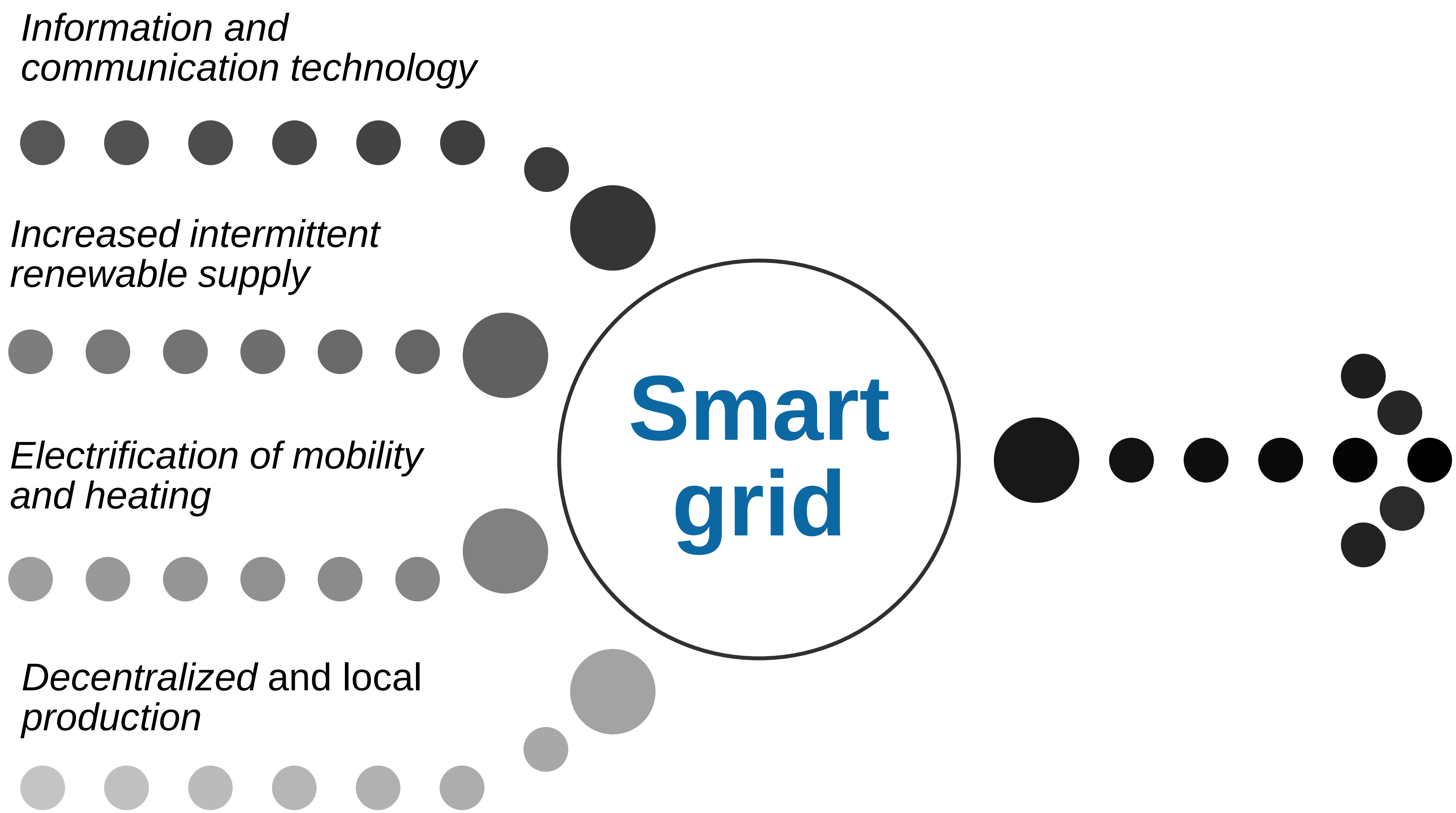
Developments



A smart grid system needs an active demand side → untapped resource of ***flexibility*** in the short term

Demand response (DR)

"changes in electric usage by **end-use consumers** from their normal load patterns in response to changes in electricity prices and/or incentive payments designed to adjust electricity usage, or in response to the acceptance of the consumer's bid, including through **aggregation**" (ACER, 2012)

A way end-users can become active market participants through **aggregation**

- Directives 2009/72/EC concerning common rules for the internal market in electricity
- Energy Efficiency Directive 2012/27/EU
- ENTSO-E 2013 Demand Connection Code
- ACER 2012 Framework Guidelines on Electricity Balancing

The European Smart Grid

- The Smart Grid (SG) is an *evolutionary* rather than *revolutionary* concept
  - Changing electricity system is demanding structural adaptation, both physically and institutionally
    - Developments are imposing **technical** and **financial** challenges
- SG related services→ an active demand side
  - In search of an untapped resource of *flexibility*, especially in the short term
- Residential end-users account for ~ 1/3 of European electricity consumption

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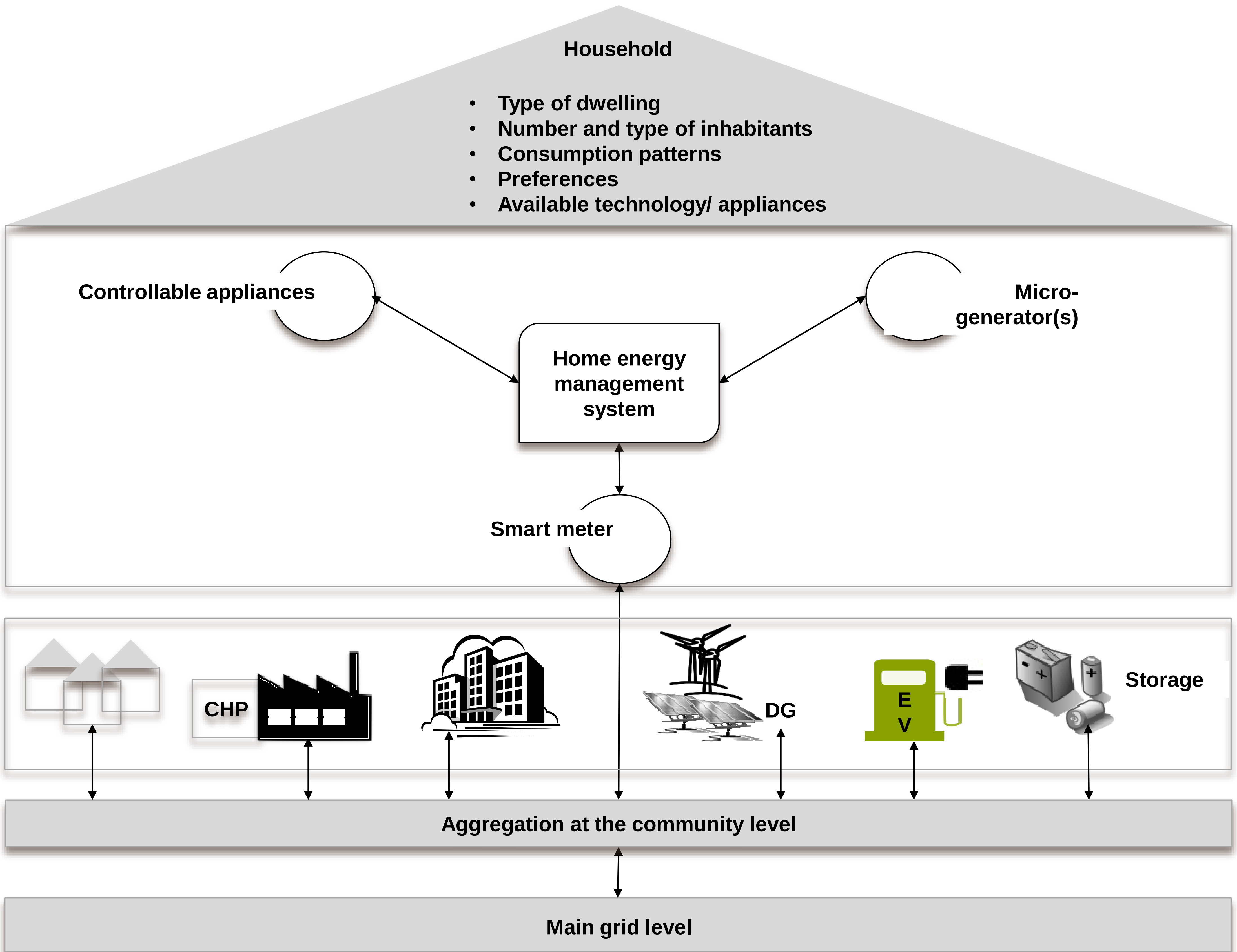
The complexity of harvesting DR through aggregation



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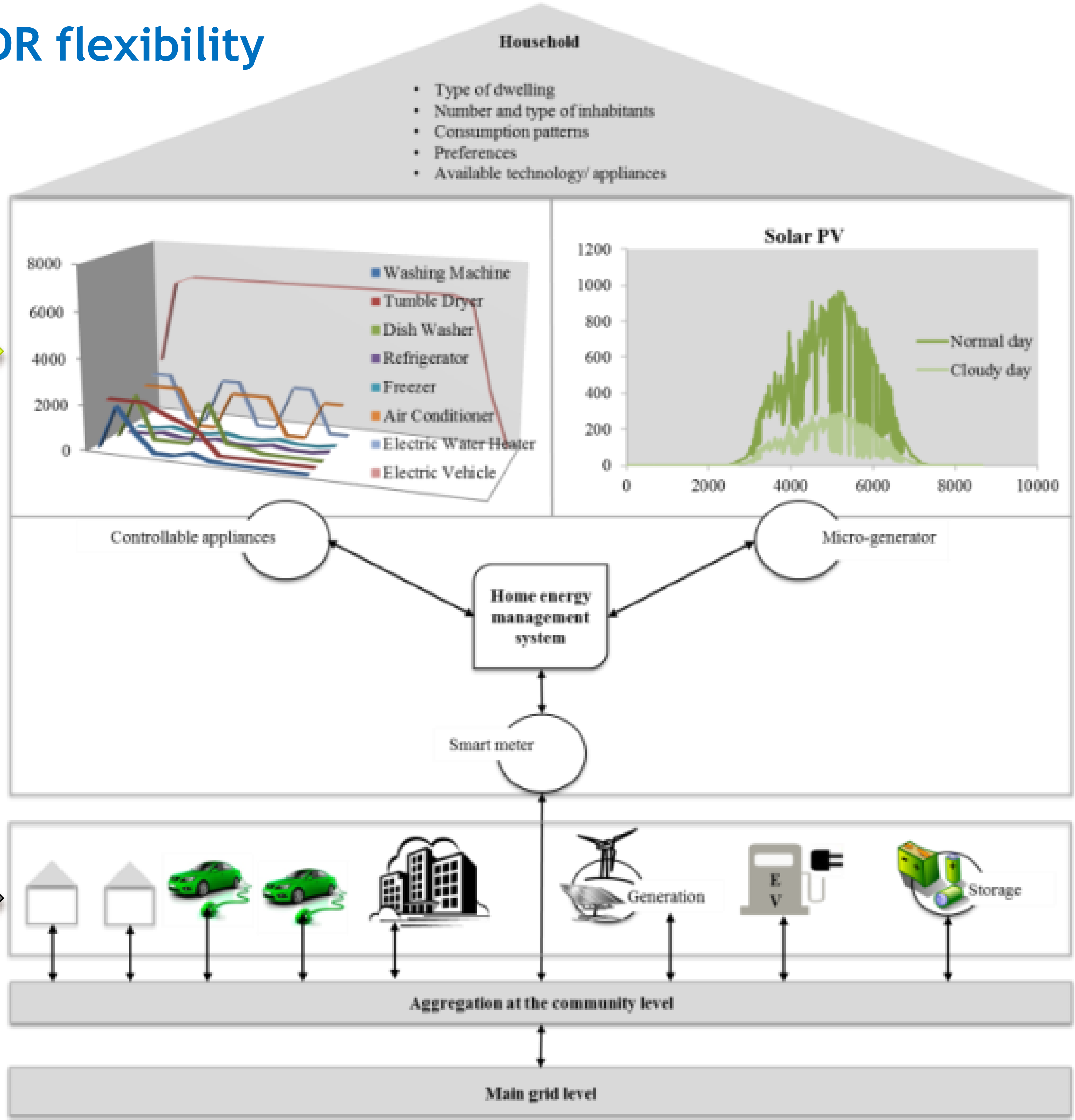
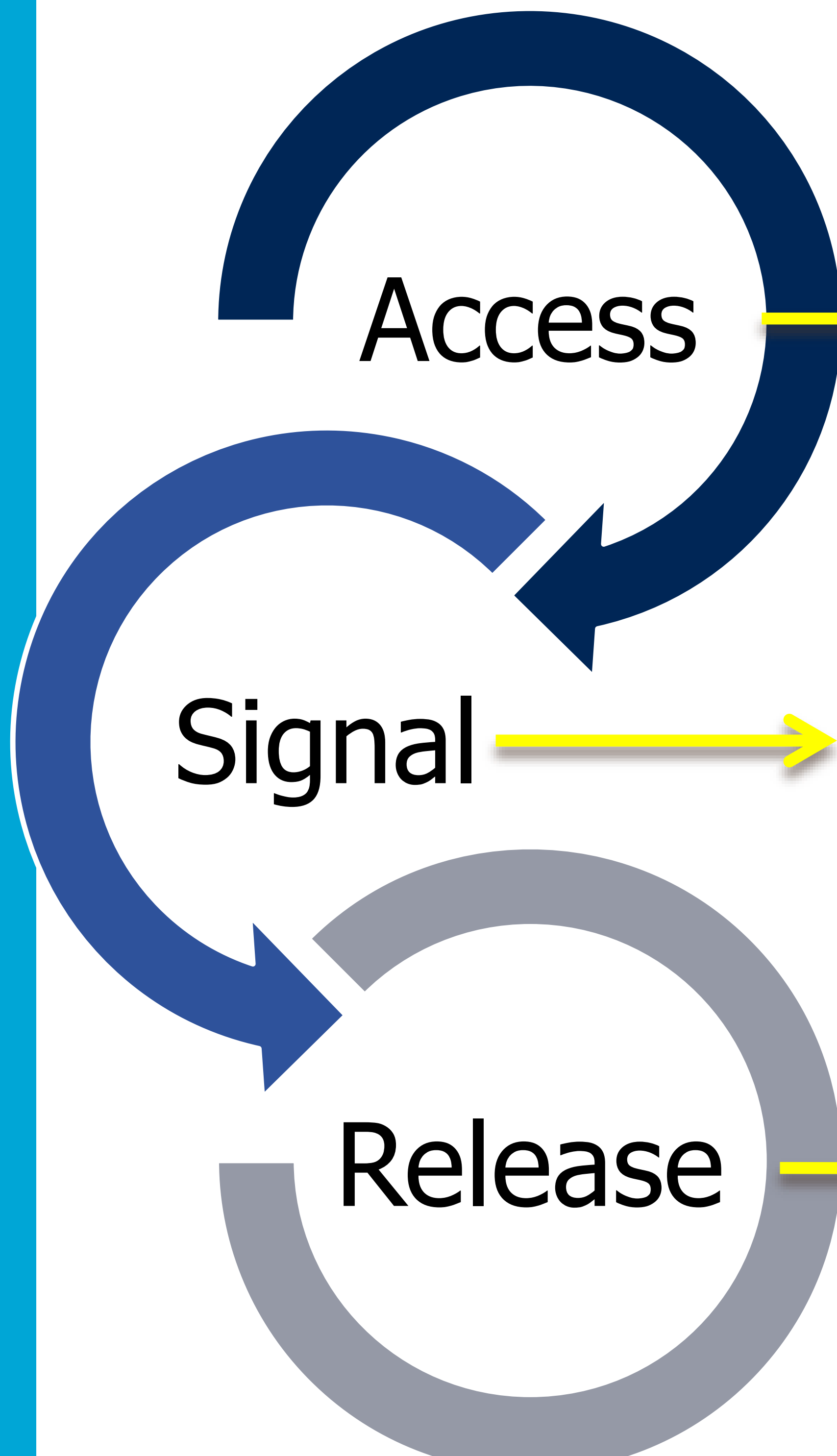
Household DR flexibility

Individual households provides small amounts of flexibility

Aggregation allows for real potential



Harvesting DR requires clarification of where the *money* is at…



Who ?

- 3rd party
- BRP
- Retailer

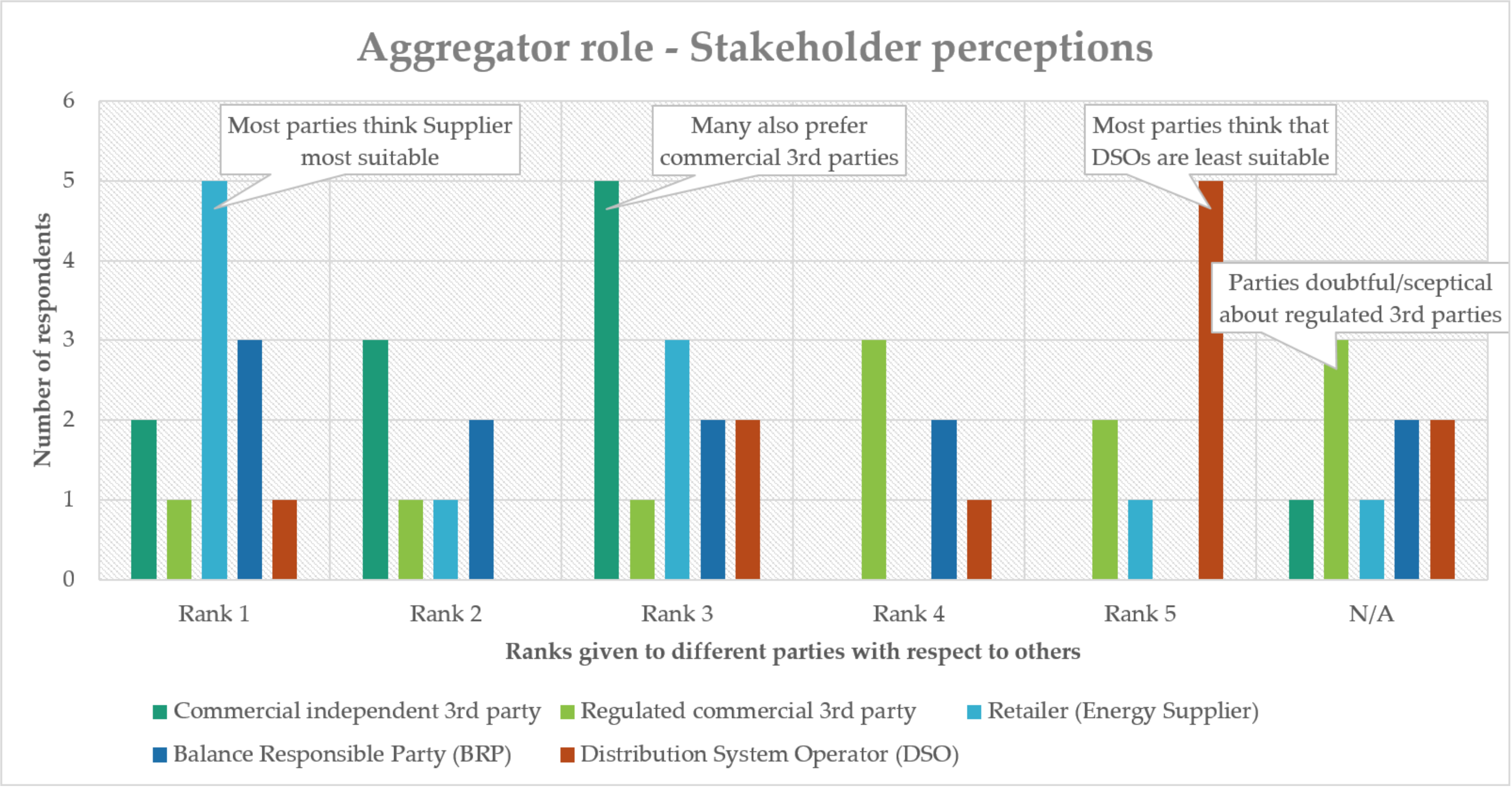
How?

- Incentive-based (controllable/volume)
- Price-based (behavioral)
- System signal

When?

- Day-ahead market
- Intraday market
- Balancing market
- TSO congestion
- DSO congestion

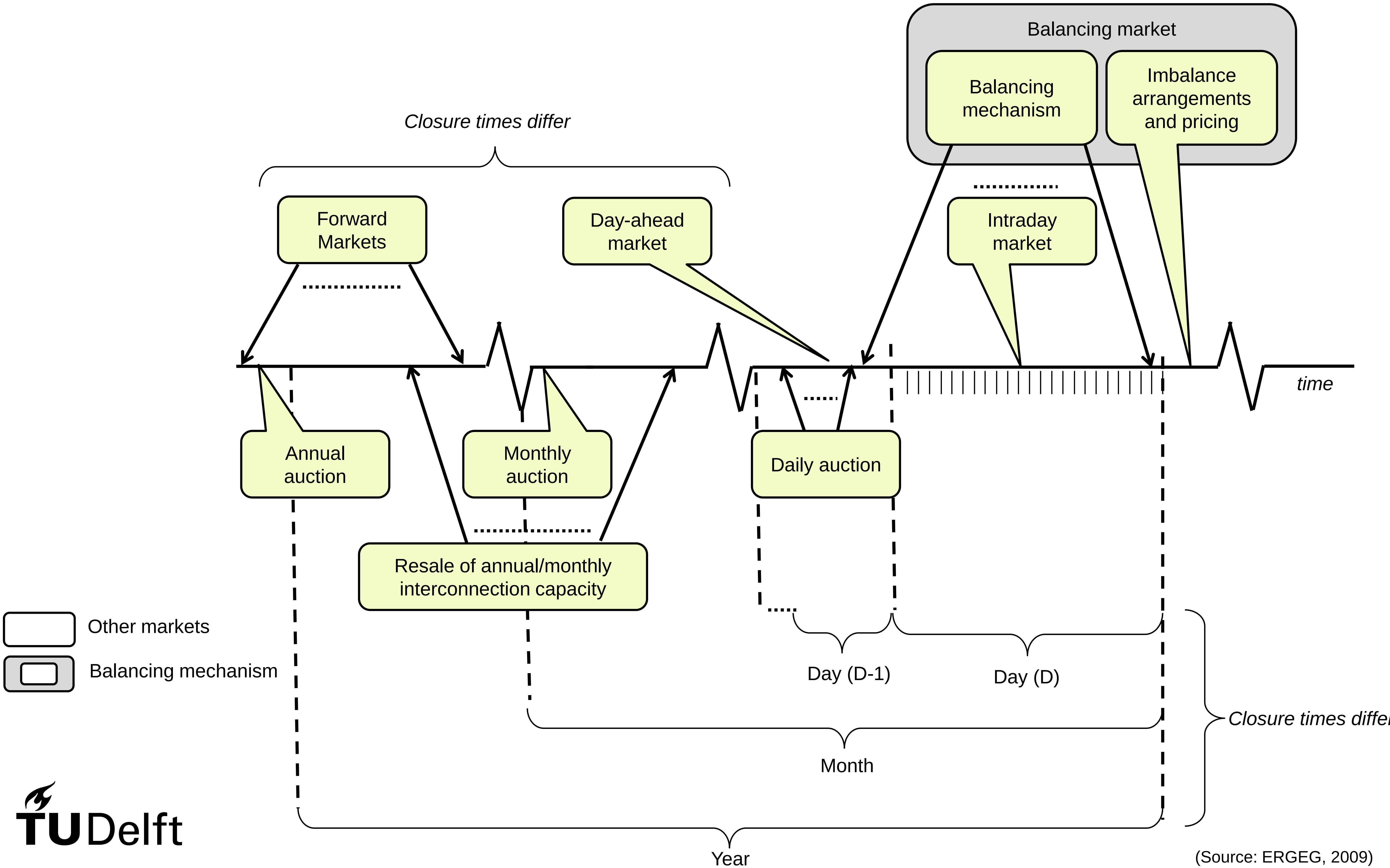
Aggregation – by whom?



- Six large utilities (from both within Netherlands and outside),
- One distribution system operator,
- A representative from the Dutch Ministry of Economic Affairs,
- A European industry lobby group,
- One established independent aggregator from France, and
- One potential aggregator (a start-up awaiting market penetration)

(ref. Koliou et al., 2015)

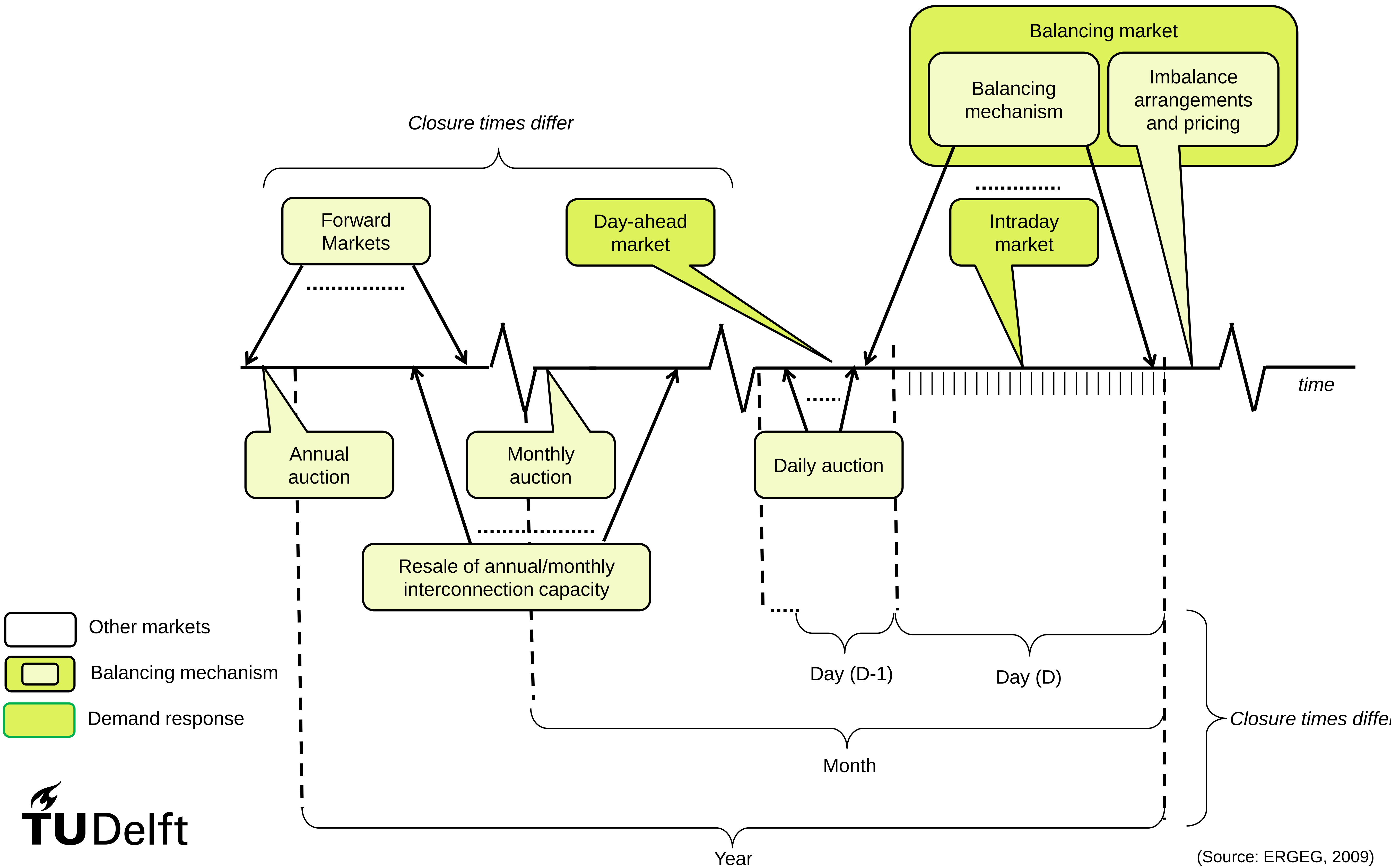
Electricity markets and time scales



(Source: ERGEG, 2009)

Electricity markets

Narrowing the focus to what is feasible for demand response



(Source: ERGEG, 2009)

Design elements for aggregate DR participation in various markets

Market	Forward	Spot		Balancing		
		Day-ahead	**Intra-day**	**Primary** (Frequency Containment Reserves)	**Secondary** (Frequency Restoration Reserves)	**Tertiary** (Replace ment Reserves)
Event Trigger	Economic Dispatch	Economic Dispatch	Economic Dispatch	System Imbalance	System Imbalance	System Contingency
Response Time (how long until release?)	Years to 1 day ahead	1 day-ahead	Minutes to hours ahead	≤1 min to ≤15 min	<30 sec to >15 min	≥15 min
Duration	Minimum of 1 day	1 day	Several hours	Up to 15 min.	Up to 30 min.	Up to hours

Ref. (Koliou et al., 2014)

Access to demand response flexibility

The aggregator: a competitive market party

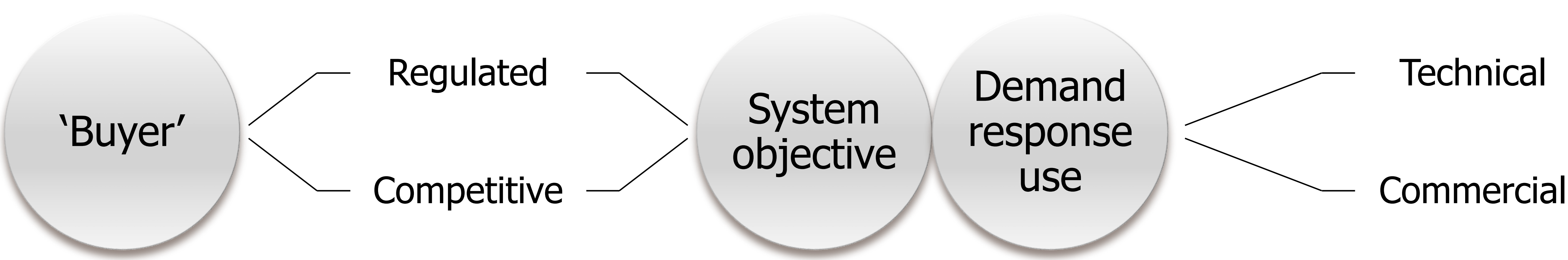
Retailer

- EU supplier hub model
  - Already the customer point of contact for end-users
  - Access to markets & customers
  - Already have a balance responsibility

3rd party

- New market actor
  - Simply provides demand response products and services (specialized)
  - Needs to establish relationships with all market actors

Flexibility buyer characteristics



(ref. Koliou et al., 2015

Compensation options for BRP, aggregator and consumer (adapted from ref. Eurelectric (2015))

Method	Financial compensation	Assessment
Bilateral agreement established amongst the parties	Final compensation is agreed between the aggregator, BRP and supplier.	+ If such contracts are standardized this may initiate a large scale roll-out and therefore facilitate market access for independent aggregator – Incumbent BRPs and suppliers may exhibit market power and refuse contracts to aggregators
Regulated agreement established by the regulator	The aggregator directly compensates the respective BRP and or supplier at a regulated price for accessing their scheduled consumption as demand response flexibility.	+ Diminishes apprehensions over the exercise of market power by incumbent BRPs and suppliers – Hinders innovative pricing solutions by aggregator – Running the risk that this type of pricing may not compensate the supplier and BRP appropriately – Such remuneration gives way to “none-market based arbitration” between the set regulated price and wholesale market prices
Corrective ‘action’ agreement based on metered data	Compensation for sales to the supplier and flex taken by the aggregator. BRP and supplier are compensated by their customers at the contracted rates. In turn, the aggregators compensate the customers for proving flexibility to them.	+ The pricing process is transparent – Meter data adjustments may not be fully transparent for the customer – Considerable effort to correct adjusted volumes is needed by the system operator – Difficult to implement for small customers

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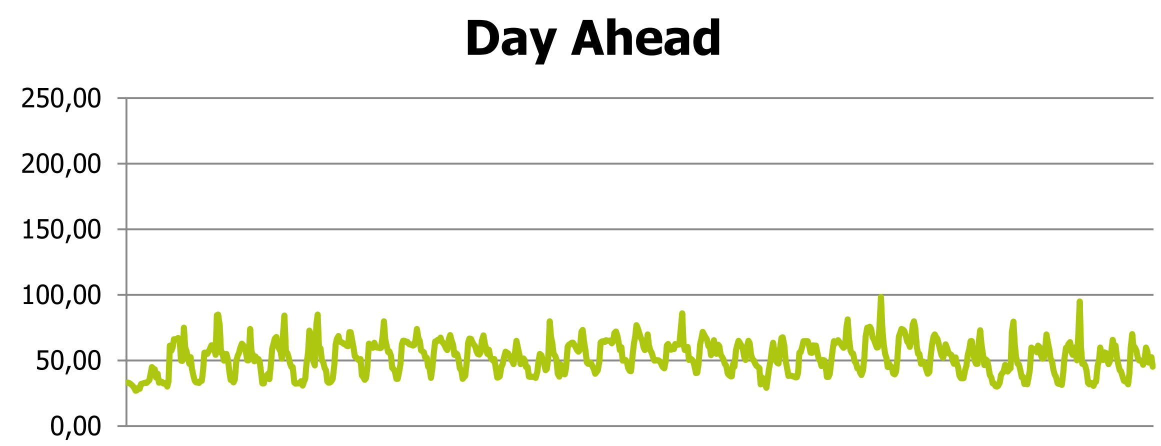
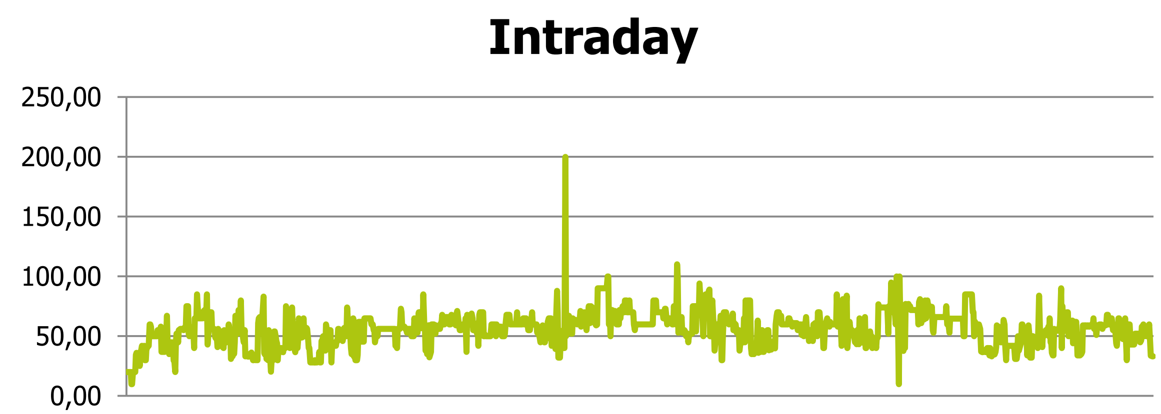
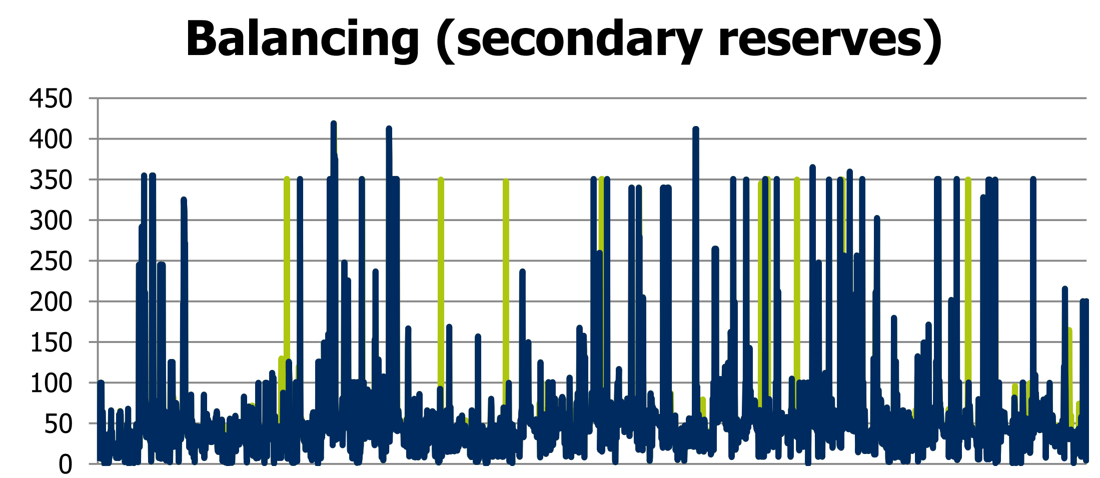
Electricity markets and consumption: e.g. the Netherlands

- 40 % of electricity consumed is contracted in forward arrangements
  - Bilateral agreements
- 45 % of the electricity consumed is traded in the day-ahead market
  - Average price: 52 €/MWh
  - Maximum price: 98 €/MWh
- Intraday is less than 5 % of total consumption
  - Average price: 56 € /MWh
  - Maximum price: 200 € /MWh
- Balancing market
  - Average price: 58 €/MWh
  - Maximum price: 420 €/MWh







ref. (APX, 2013;TENNET, 2013; NPspot, 2013)

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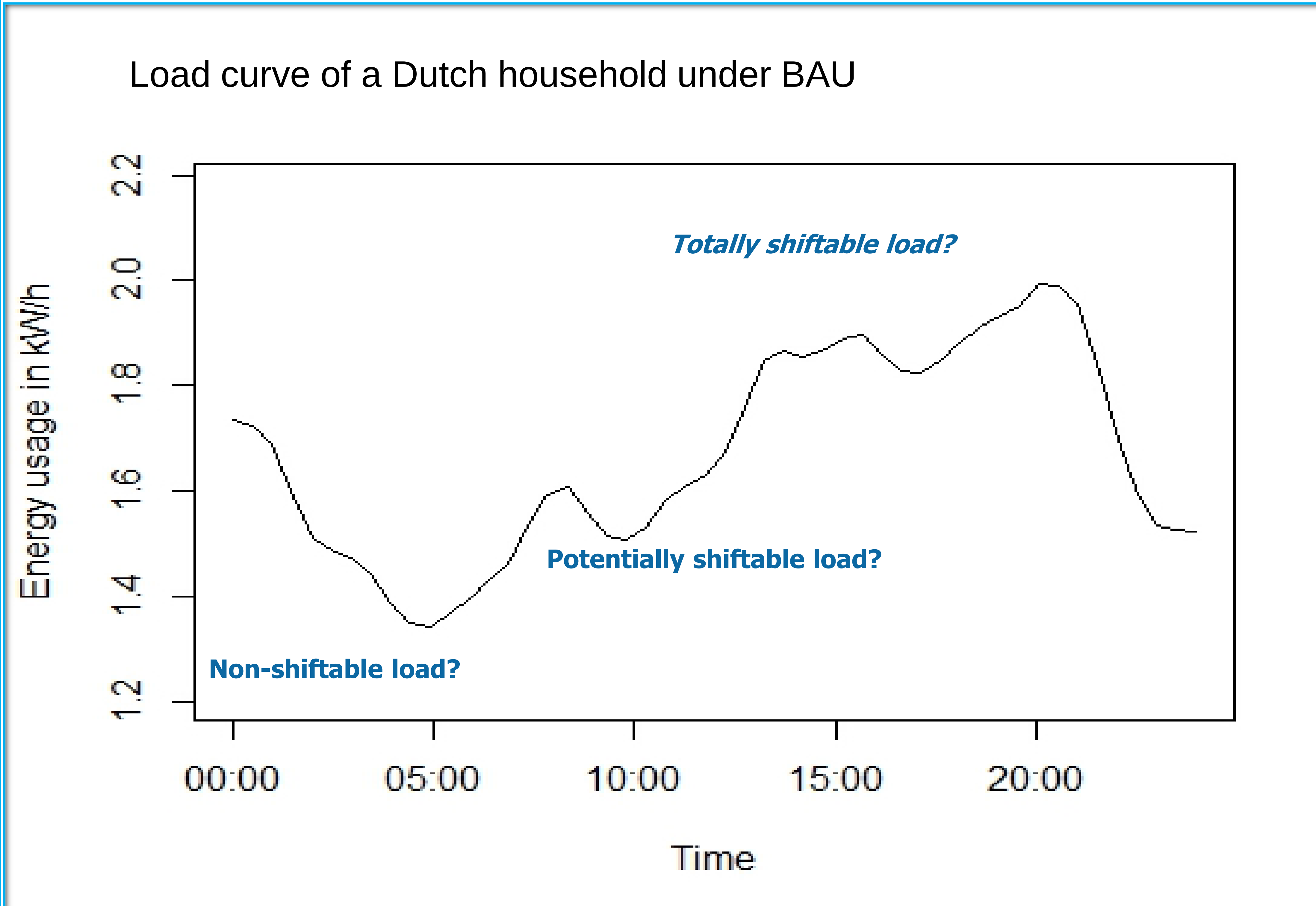
Load curve of a Dutch household under BAU



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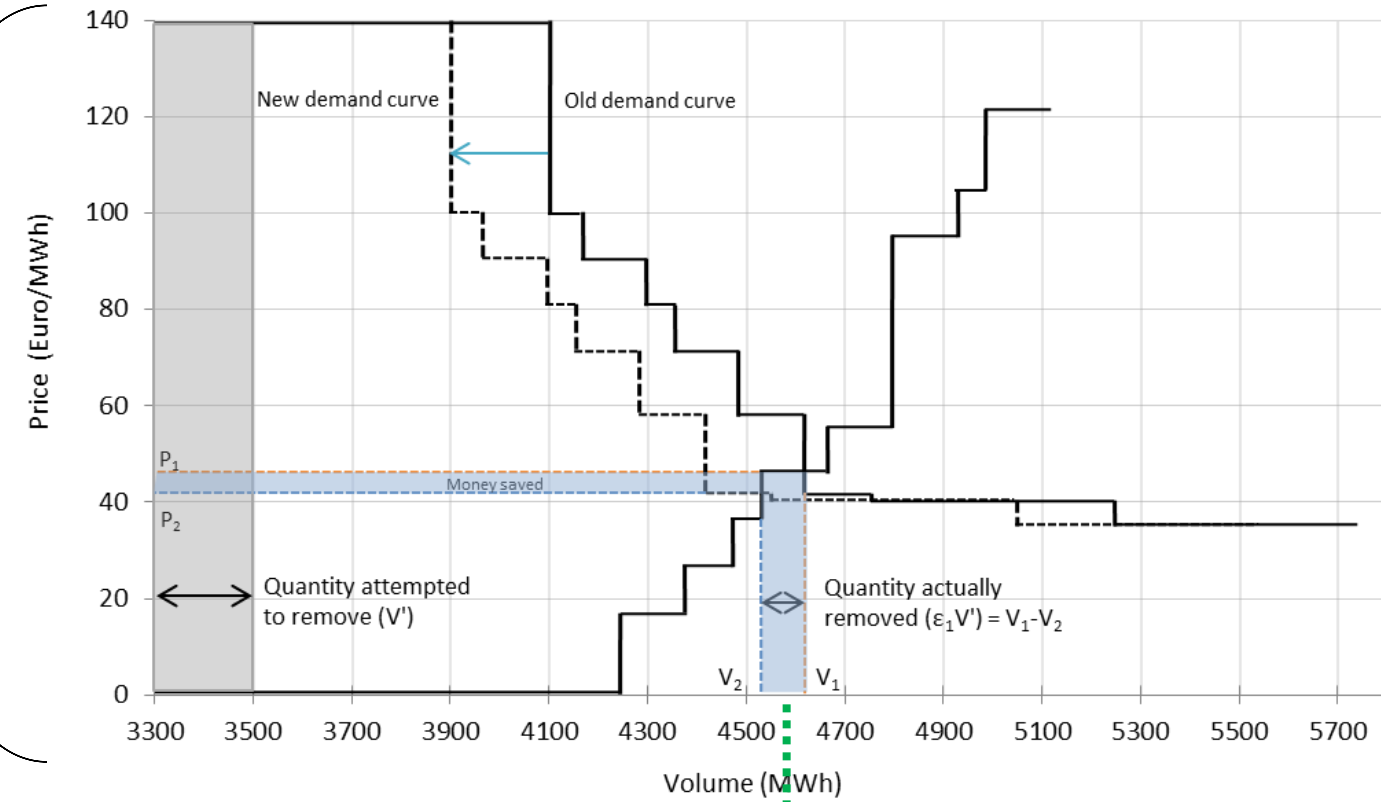
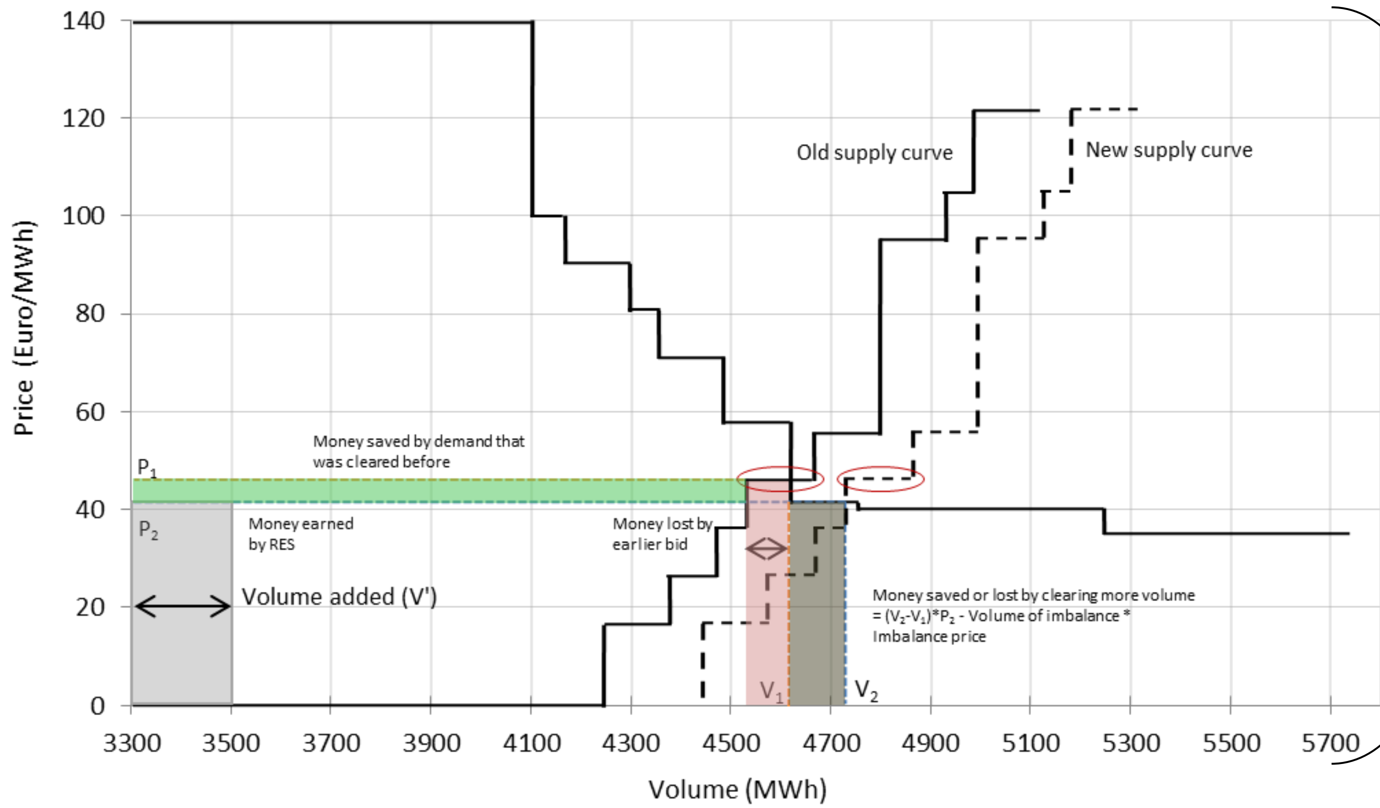
Economic dispatch and the creation of imbalances

Available *DR flexibility does not equal the* ***cleared*** *volume in the market*





Volume *removed in DR hour is consumed in another hour*

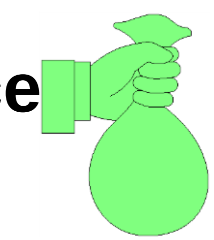
Ref. (Muhaimin, 2015)

Incentive based mechanisms

	Allowed max in APX	Max price reached	Yearly average price	Min price reached	Allowed min in APX
Day ahead market prices in €/Mwh	€ 3,000.00	€ 142.38	€ 39.16	€ 0.01	-€ 5,000.00
Intraday market prices in €/Mwh	€ 99,999.90	€ 500.00	€ 59.96	€ 0.00	-€ 99,999.90

1.44 Kwhs per cycle × 70 = Minimum offer needed for APX (0.1 MWh)

@ average price



	Total: Day ahead	Total: Intraday	Per customer: Day ahead	Per customer: Intraday
Min offer once (€)	€ 3.94	€ 6.03	€ 0.06	€ 0.09
Offer once per week over the year (€)	€ 204.42	€ 313.19	€ 2.92	€ 3.93
Offer every day of the year (€)	€ 1,434.89	€ 2,198.32	€ 20.50	€ 31.40

(ref. Koliou et al., 2015)

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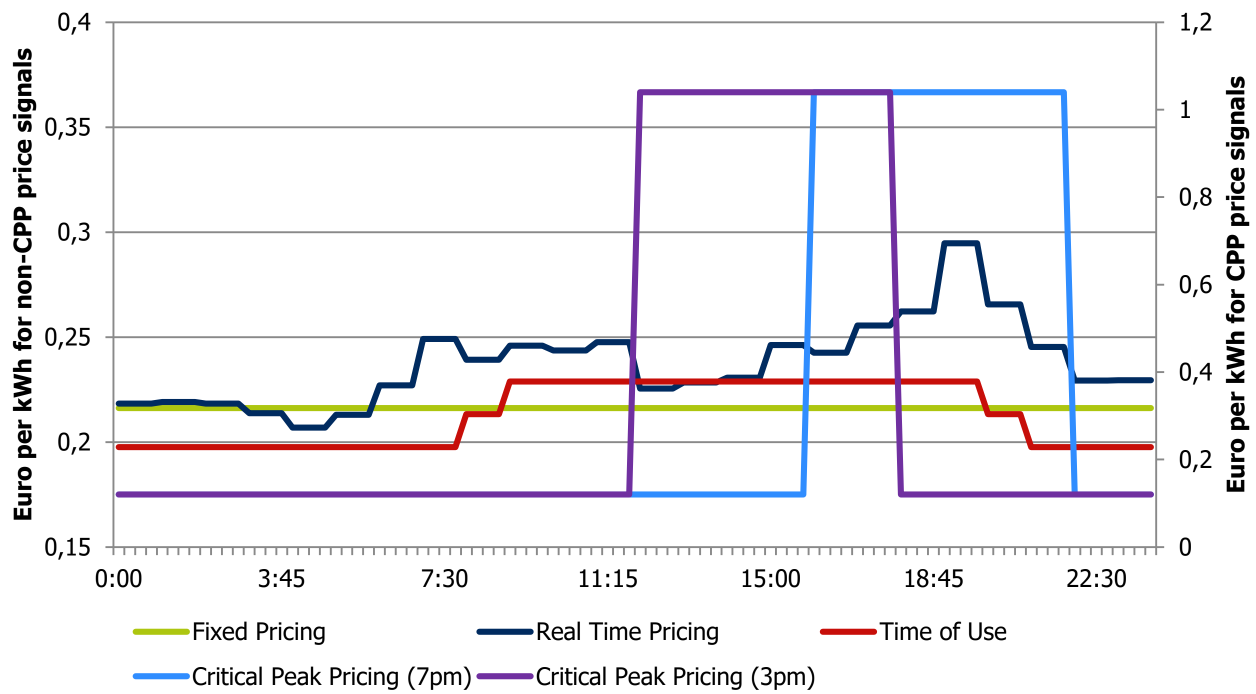
Price based mechanisms

Case study using APX prices for the Netherlands

Price band	Hours
Time of Use Pricing	
Shoulder	0800-0900 & 2000-2100
Peak	0900-2000
Base	0100-0800 & 2100-2400
Critical Peak Pricing	
Base	0000-1200 & 1800-0000 0000-1600 & 2200-0000
Critical Peak	1200-1800 & 1600-2200



- Fixed pricing
- Time of use (TOU)
- Real time pricing (RTP)
- Critical peak pricing system peak (CPP-s)
- Critical peak pricing-residential peak (CPP-R)

- *Findings from price design:*
  - CPP is the most profitable
    - Should consider the residential peak for small end-users
    - Consider the system peak for large industrial users
  - TOU pricing may be profitable with a seasonality component
  - RTP is not profitable for consumers on an average day, need extreme prices to make a profit
    - Too much of a 'time constraint' for end users… unless there is automation

(ref. Koliou et al., 2013)

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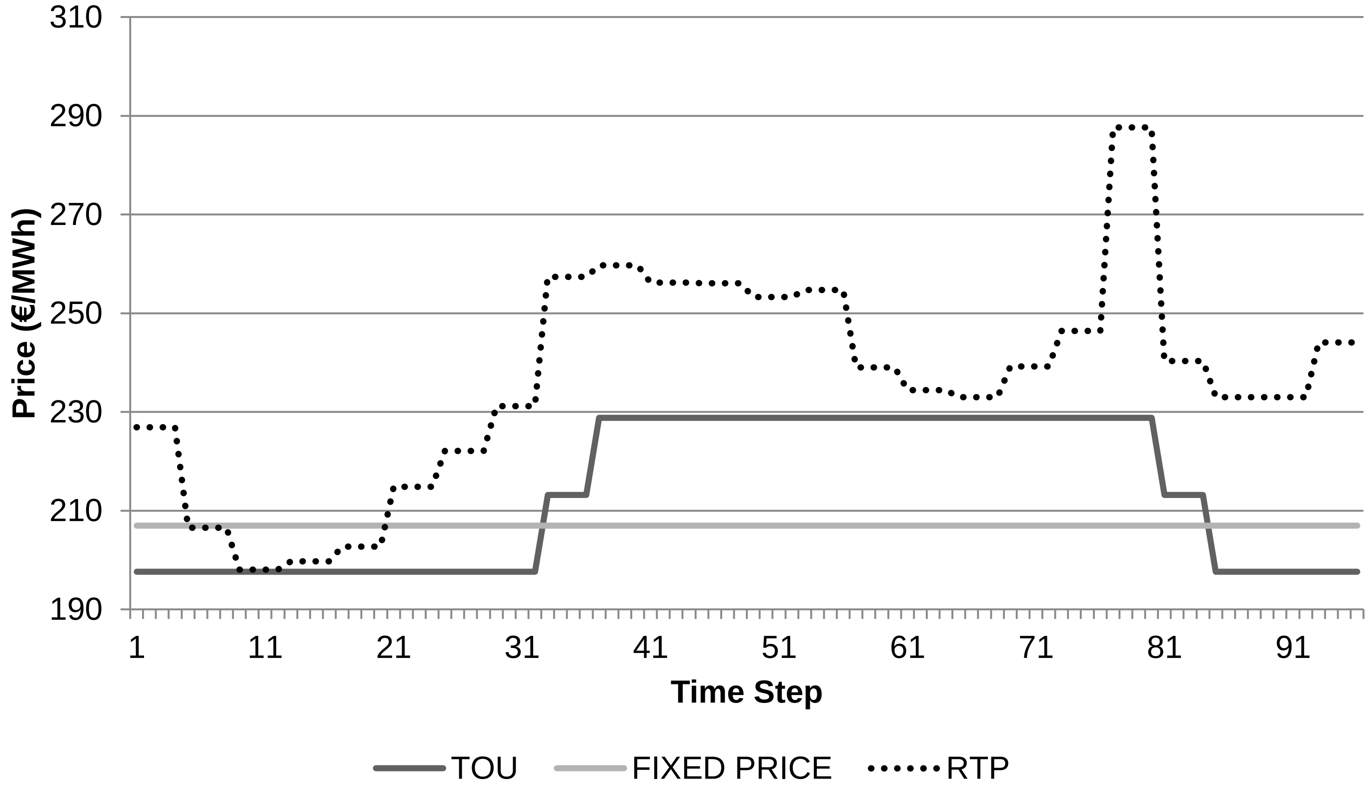
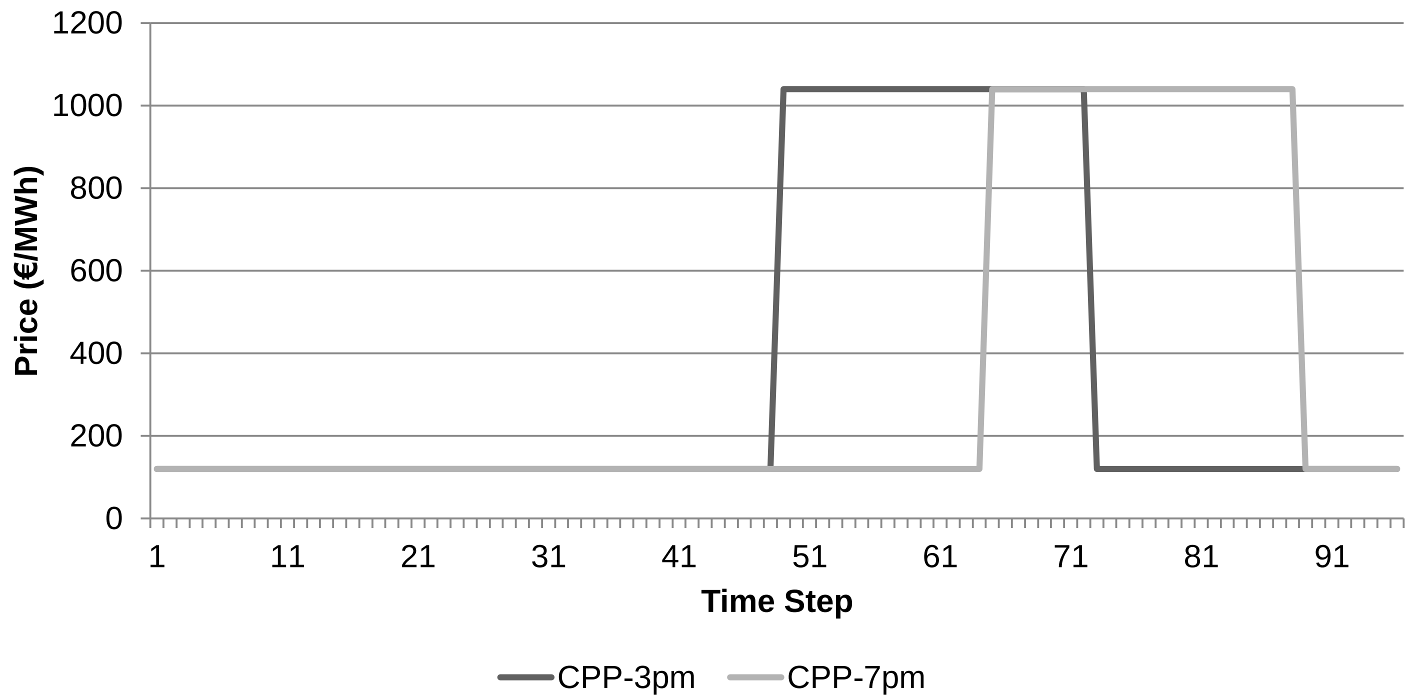
Price-based Demand Response



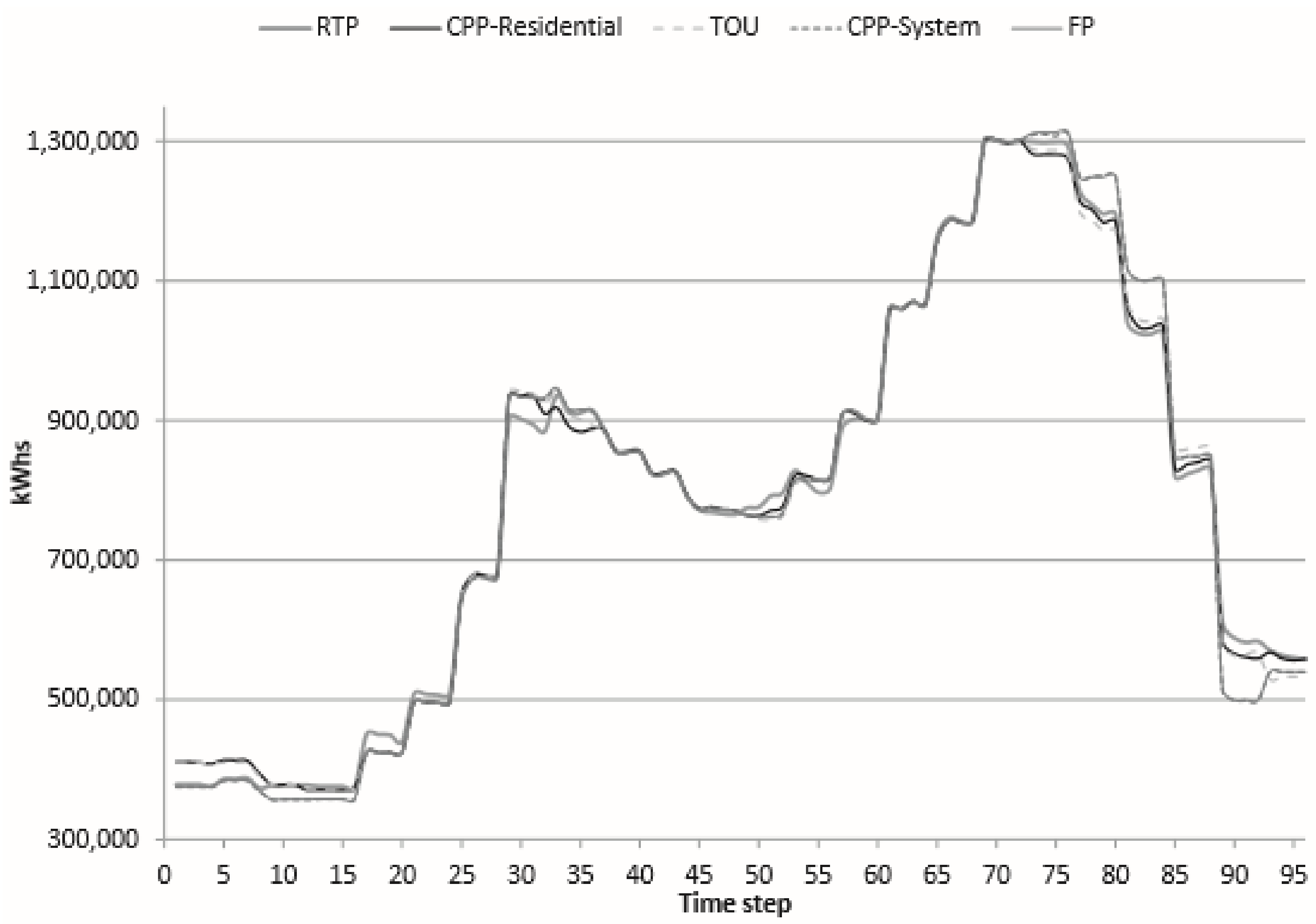
- **Fixed Price (FP)**
- **Time of Use (TOU)**
- **Real-time price (RTP)**

- **Critical Peak Price (CPP)**



Price-based Demand Response

	FP	TOU	RTP	CPP-System	CPP-Residential
Average cost per household	2.32€	2.23€	2.59€	2.63€	5.29€
Country cost (millions of €)	16.39€	16.47€	18.45€	31.29€	34.25€



- Total maximum shift as part of the country curve is actually less than 1.2%
- Even with RTP maximum yearly savings for a household are no more than 100 euro

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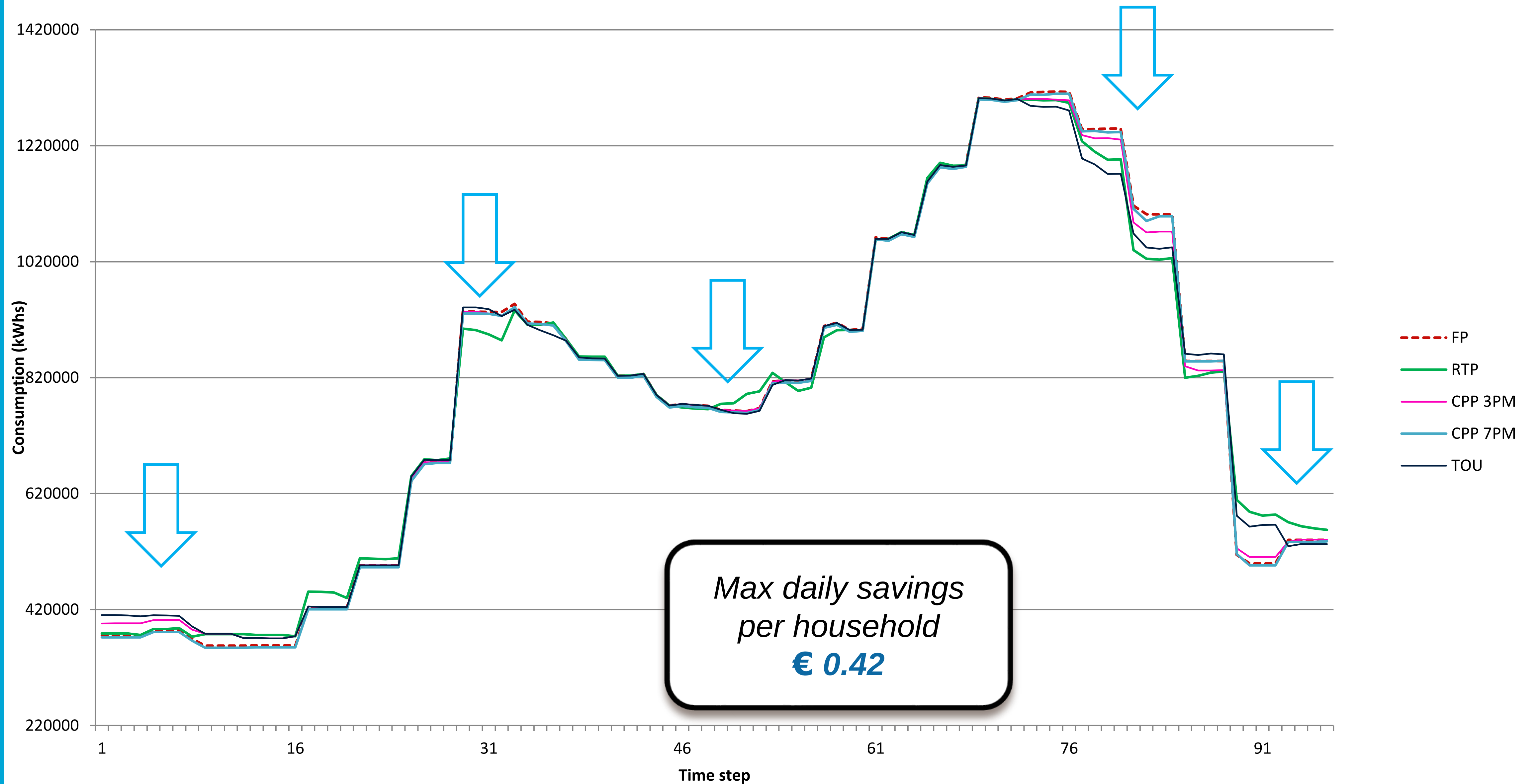


	Value	FP	RTP	TOU	CPP-3PM	CPP-7PM
Average household cost before shifting	€/day	**2.3**	**2.35**	**2.26**	**2.47**	**2.51**
Average household cost after shifting	€/day	**2.3**	**2.31**	**2.23**	**2.05**	**2.11**
Daily expenditure by all households	*Million €/day*	***16.39***	***16.59***	***16.47***	***12.84***	***14.05***

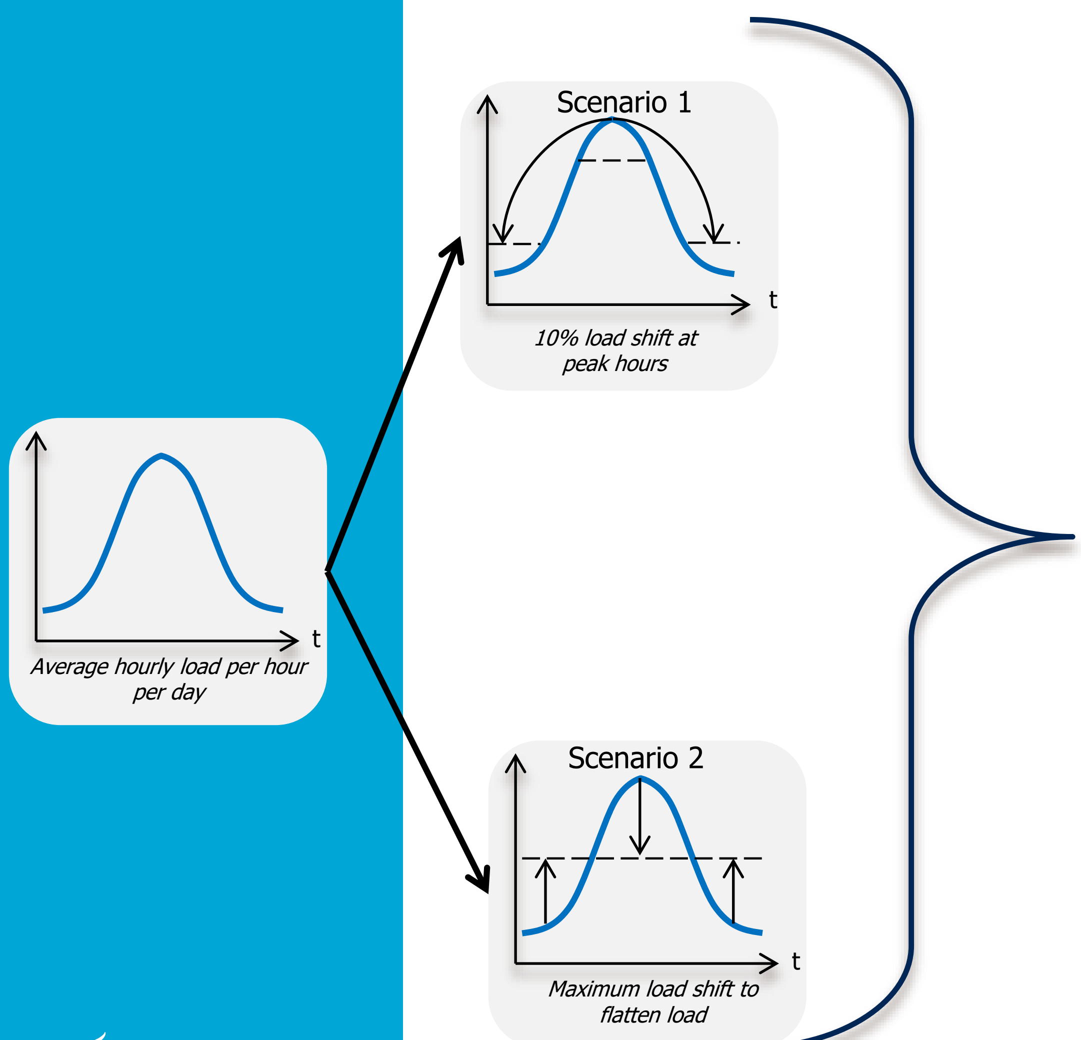
Comparison of expenditure on electricity by an average Dutch household and the whole country given a specific price signals (Koliou et al., 2013)

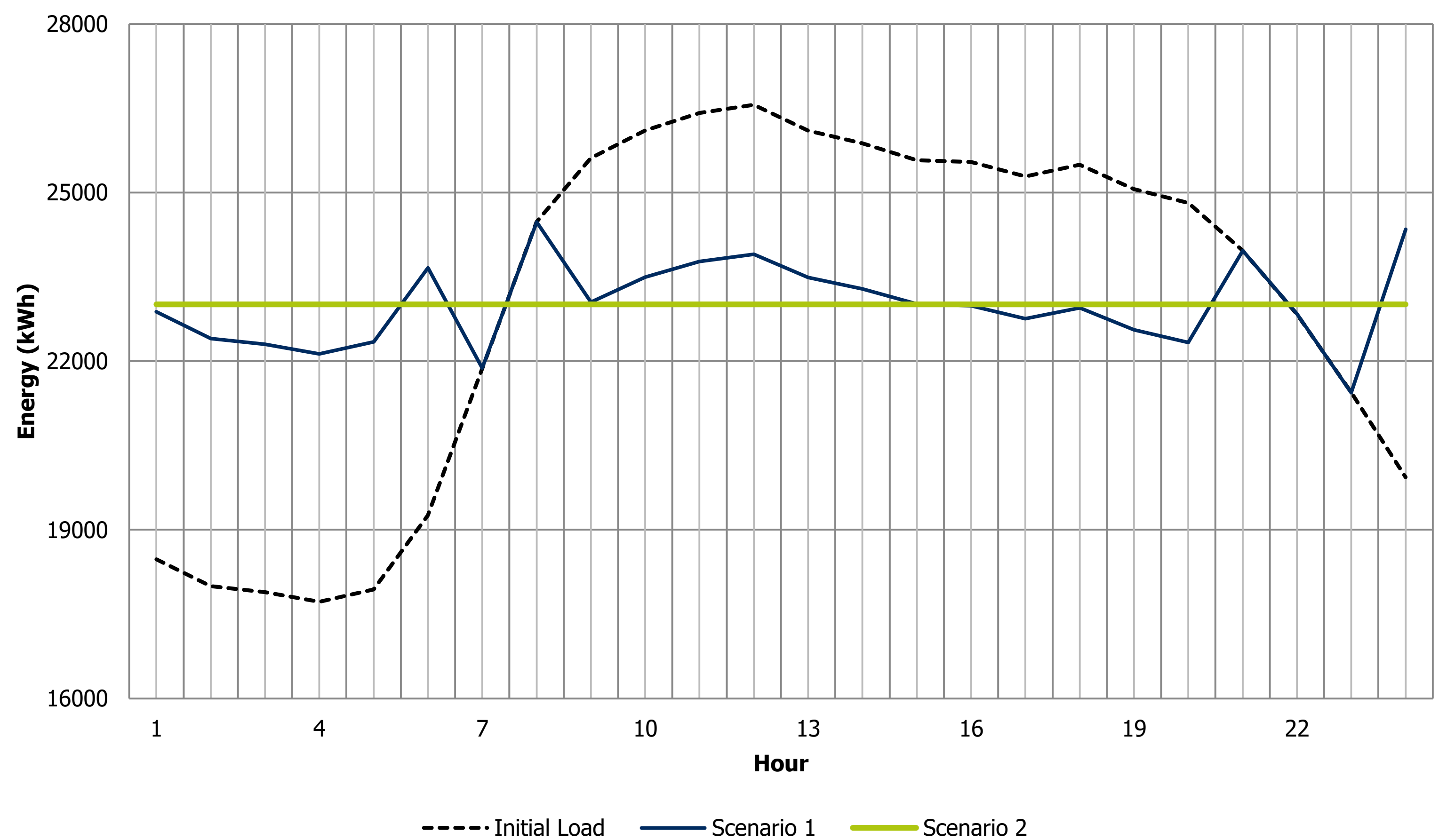
Demand response in distribution

Case study Sweden: incentivizing load shifting for cost reduction in distribution

Peak demand is and continues to be the main cost driver in distribution

- Exploring two load skirting scenarios… How do they impact costs?



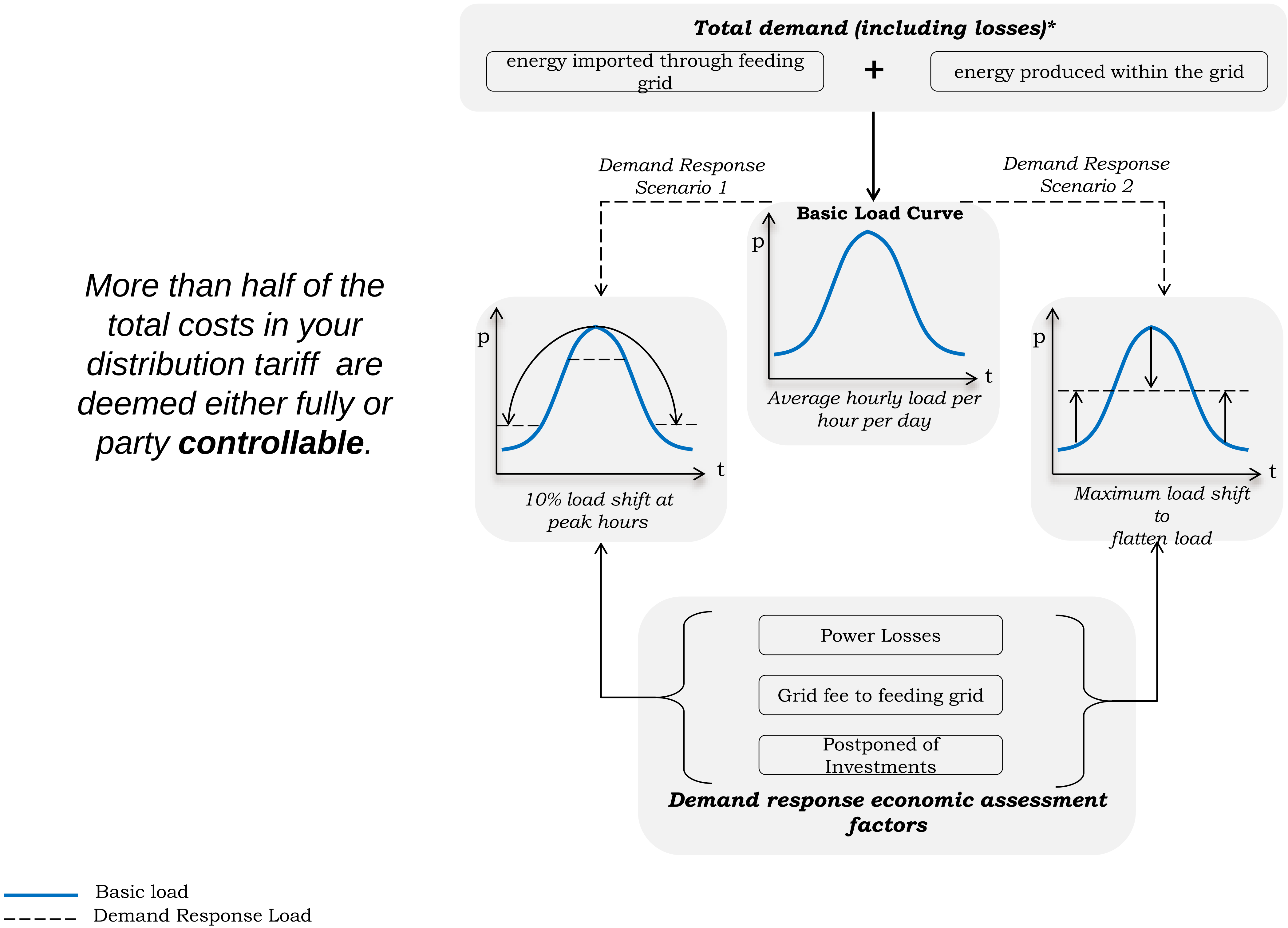


*Peak hours in this distribution system 09:00-20:00

(Ref. Koliou et al 2015)

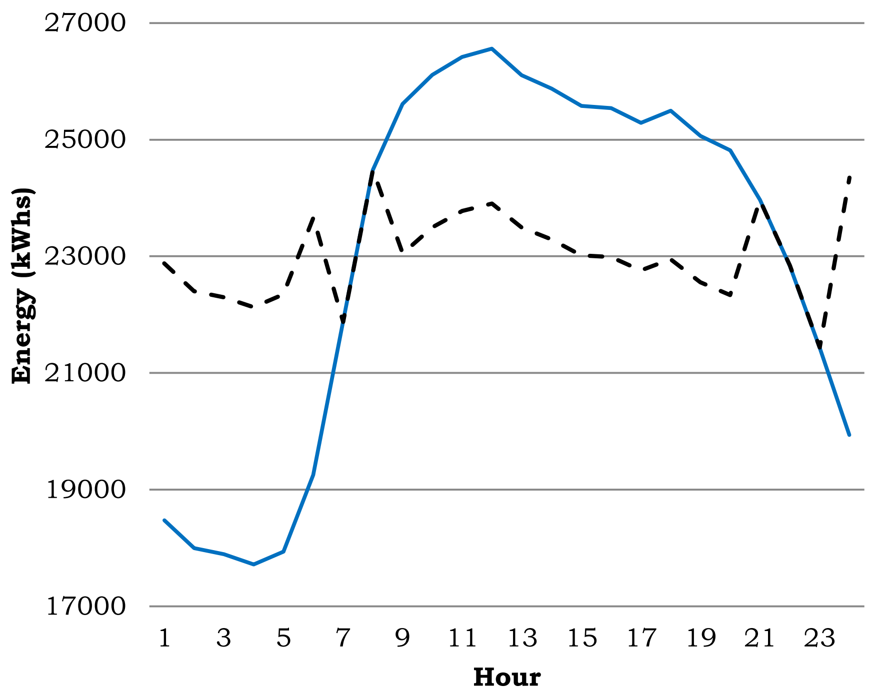
Incentivizing DR through dynamic grid pricing

*More than half of the total costs in your distribution tariff are deemed either fully or party **controllable**.*



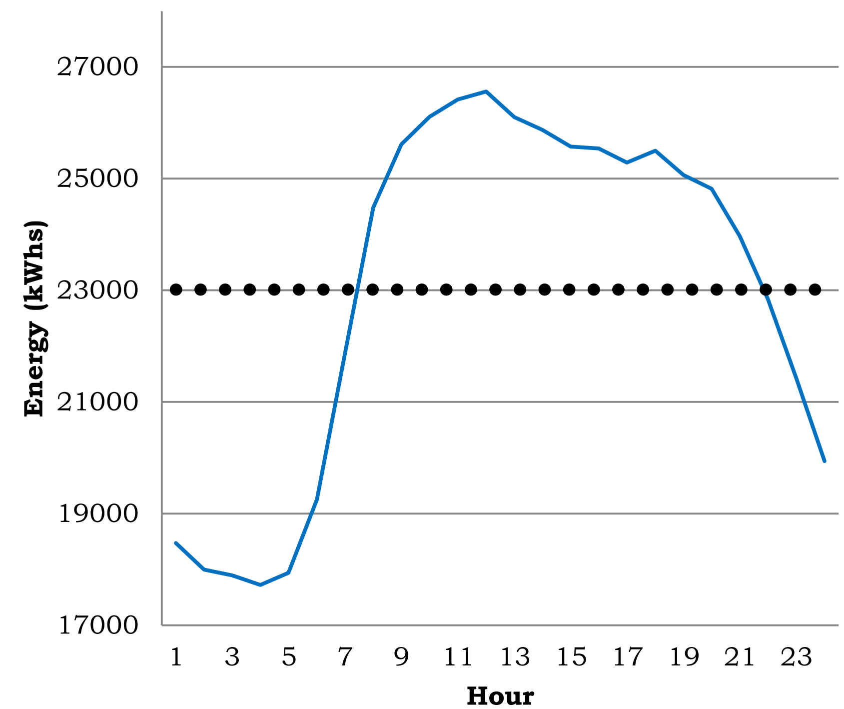
* Sala-Heby Energi Elnät AB distribution load data 2007 to 2012

Demand Response
Scenario 1, 10% load shift



Maximum yearly savings of ~**14€** per customer in the system

Demand Response
Scenario 2, flat load



Maximum yearly savings of ~ **53€** per customer in the system

Possible savings from DR in distribution

		Scenario 1: 10% load shift	Scenario 2: uniform load
Value of reduced power losses	Decrease in mean arithmetic loss over the year (%)	4%	19%
	Annual difference in cost per customer (Euro)	2.1 €	9.2 €
	Total reduction in cost per year for the DSO (percent)	8%	36%
Value for subscribed maximum power (fee paid to the regional transmission system operator)	Reduction in the level of maximum power (%)	2%	51%
	Annual reduction in cost per customer (Euro)	3.3 €	35.6 €
	Reduction in cost per year for the operator(%)	5%	46%
Value of delayed grid investments	Difference in annual cost (Euro)	109,571 €	114,420 €
	Years of delayed investments	2	43
	Annual cost decrease per customer (Euro)	8.3 €	8.6 €
	Total possible yearly savings	**13.7 €**	**53.4 €**

Making Demand Response work

Access **Who?**

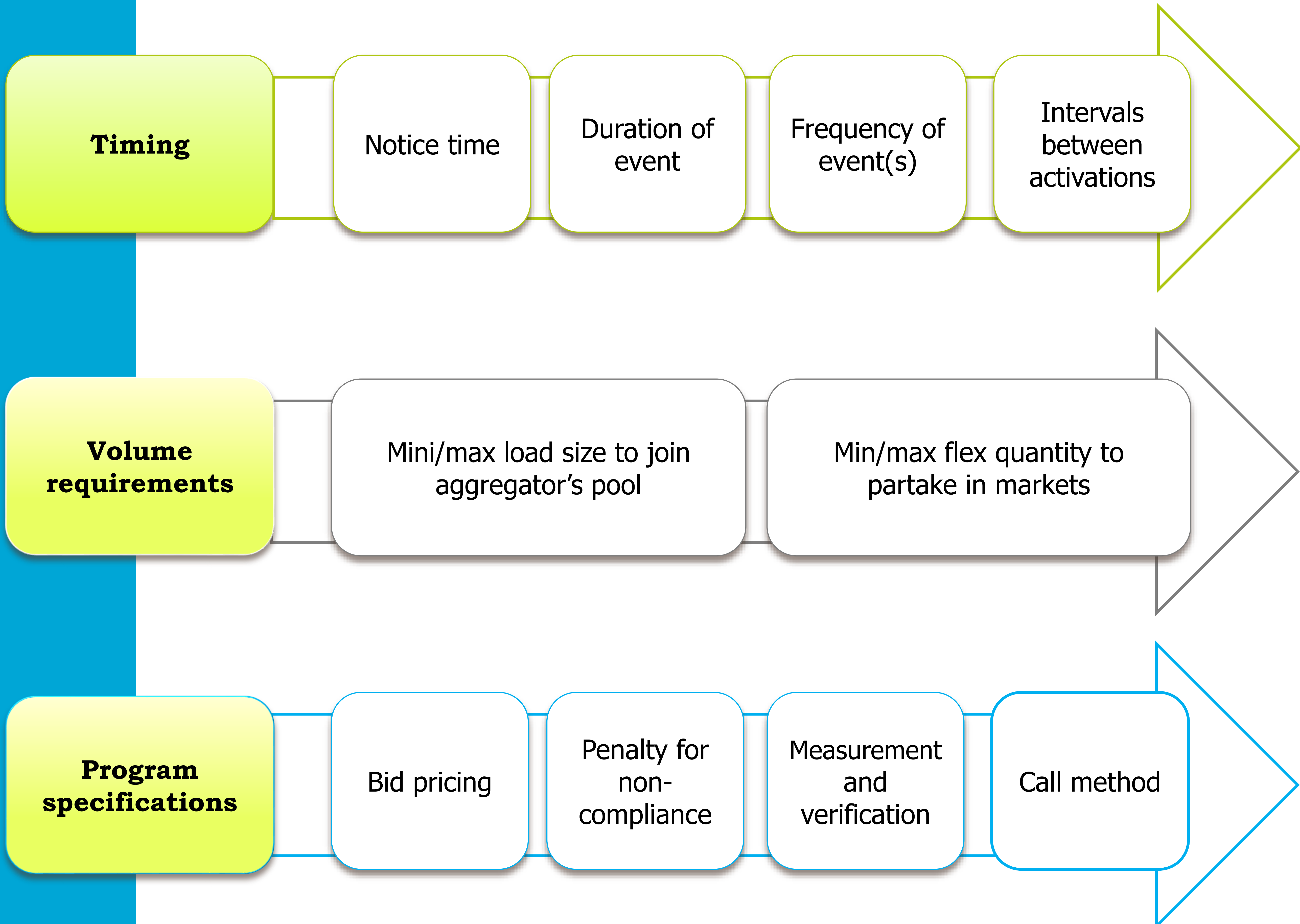
Signal **How?**

Release **When?**

Facilitate equal participation of aggregated DR alongside supply

- Demand response proliferation is inherently vulnerable to institutional barriers arising from an existing system *design framework* which caters to large units.

Timing + **Volume requirements** + **Program specifications**


Timing
Notice time
Duration of event
Frequency of event(s)
Intervals between activations
Volume requirements
Mini/max load size to join aggregator’s pool
Min/max flex quantity to partake in markets
Program specifications
Bid pricing
Penalty for non-compliance
Measurement and verification
Call method

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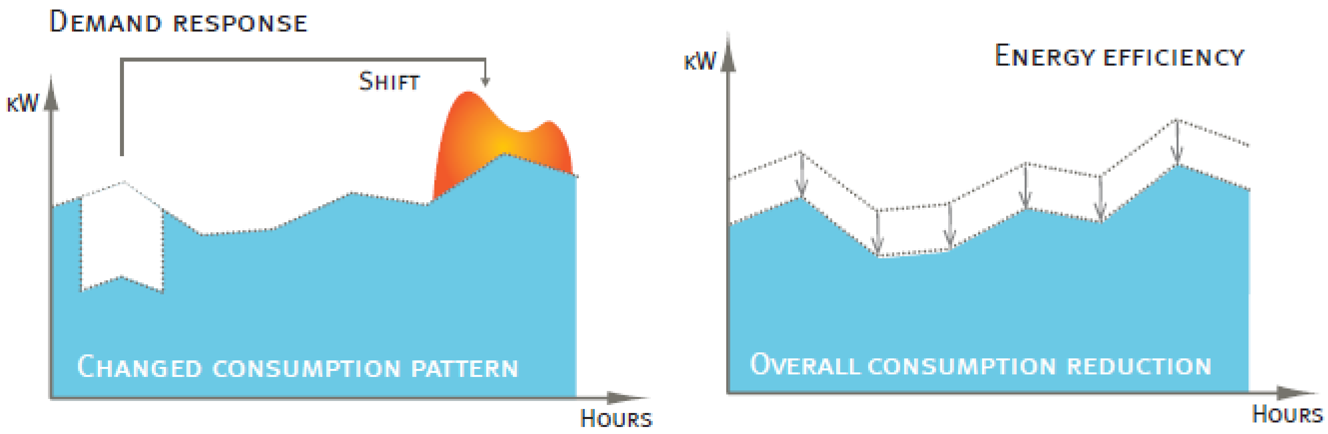
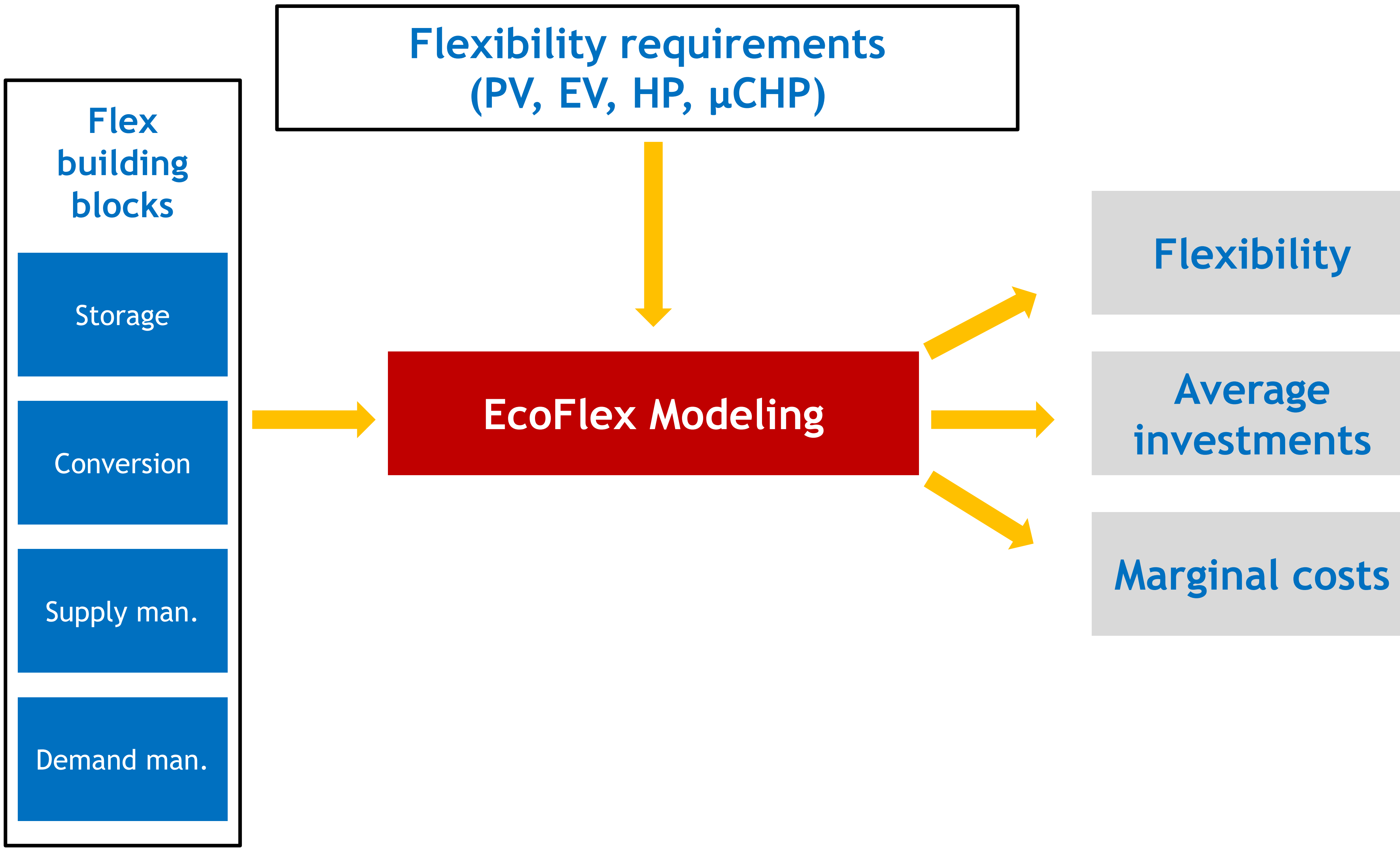
Concluding remarks

- Accessing demand side flexibility is complex and in the end may not be so profitable for the end user.
  - What are the right mechanisms for attracting end-users?
    - Incentive-based?
    - Price-price based?



- Need to figure out the market specifications
  - Timing specifications
  - Volume requirements
  - Program specifications

Flexibility Assessment



Flexibility assessment

Flexibility

$$NTR\ up = Flexibility_{provided;up} - Flexibility_{required;up}$$

$$LFI\ up = \frac{NTR\ up}{Maximum\ system\ demand}$$

Average investments

$$Amortized\ cost\ technology\ n\left(CA;n\ (\frac{€}{\mathrm{year}})\right) = \frac{Cp;n * P;n + Cc;n * E;n + Co;n * O;n}{H;n} + Cm;n$$

$$Average\ investment\ cost\left(I\ (\frac{€}{\mathrm{kW}})\right) = \frac{\sum_n^N \sum_t^T (\frac{CA;n}{(1+d)^t})}{\sum_n^N Pt;n}$$

Marginal costs

$$Marginal\ cost = \sum_n^N \left((1 - (\eta s;n * \eta r;n)) * Ce + \frac{I;n}{y;n * E;n}\right) + Cs - Cb$$

LFI: local flexibility index

AIC: average investment costs

MC: marginal costs

Example case

Flexibility requirements

PV = 270 kW, HP = 51 kW, EV = 440 kW

Flex building blocks

Li-ion 200kW
15min, 1 hr

EV storage
200kW
15 min, 1 hr,
6hr

EV smart
charging 15%
15 min, 1hr,
6hr

EcoFlex

LFI	15 min	1 hour	6 hour	12 hour
Up	-0,01	-0,01	-0,34	-0,83
Down	0,22	0,22	-0,12	-0,45

AIC	15 min	1 hour	6 hour	12 hour
Up	€ 1.320,37	€ 1.320,37	€ 92,43	€ -
Down	€ 1.591,83	€ 1.591,83	€ 95,08	€ -

MC	15 min	1 hour	6 hour	12 hour
Up	€ 3,42	€ 0,87	€ 0,09	€ -
Down	€ 3,42	€ 0,87	€ 0,09	€ -

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THANK YOU!

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