Toward Future Electricity Markets with Massive DER Penetration and Optimal Transmission-Distribution Coordination

Meng Wu
Arizona State University
July 13, 2022

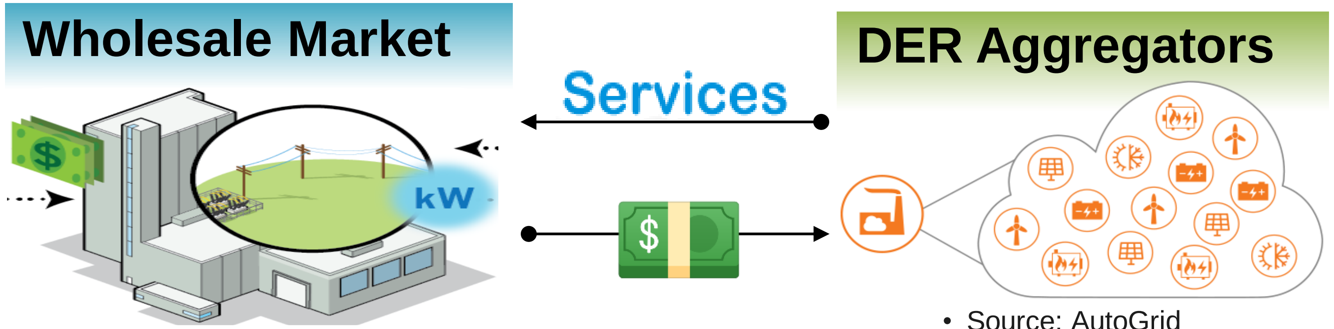
Acknowledgements

ASU Graduate Students:

Mohammad Mousavi
Retail Market Design + T&D Coordination

Zhongxia Zhang
Machine Learning + Price Forecasting

Challenges & Opportunities



• Source: PJM

• Source: AutoGrid

Market Operation

- Coordinate T&D, DER aggregators, and DERs?

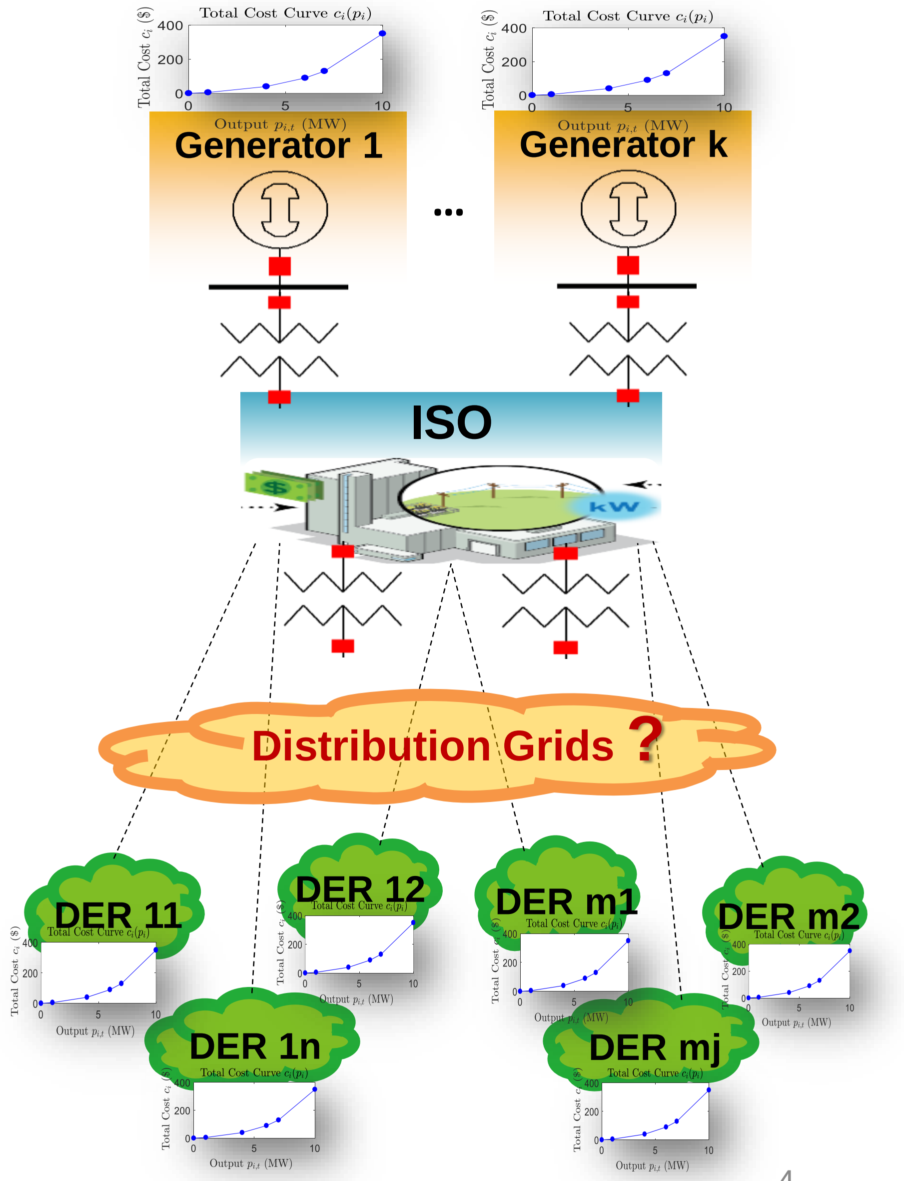
Market Participation

- Forecast Electricity price?

T&D Coordination for DER Market Integration

Today's market for DER integration:

- Solves the market clearing problem with transmission level operating constraints, generator & DER bids
- Many (aggregated) DERs entering the ISO market
- Market clearing computation burden and convergence
- ISO not observing distribution grids
- Mismatch between market/physical models
- Voltage/thermal violations in distribution grids

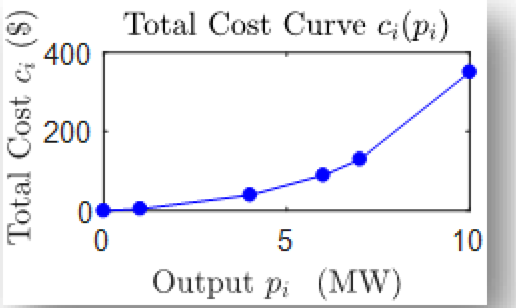


T&D Coordination for DER Market Integration

The ideal (unrealistic) market for DER integration:

- Solve the market clearing problem with transmission and distribution level operating constraints, generator & DER bids

Total generation cost curve submitted by i^{th} generator or DER



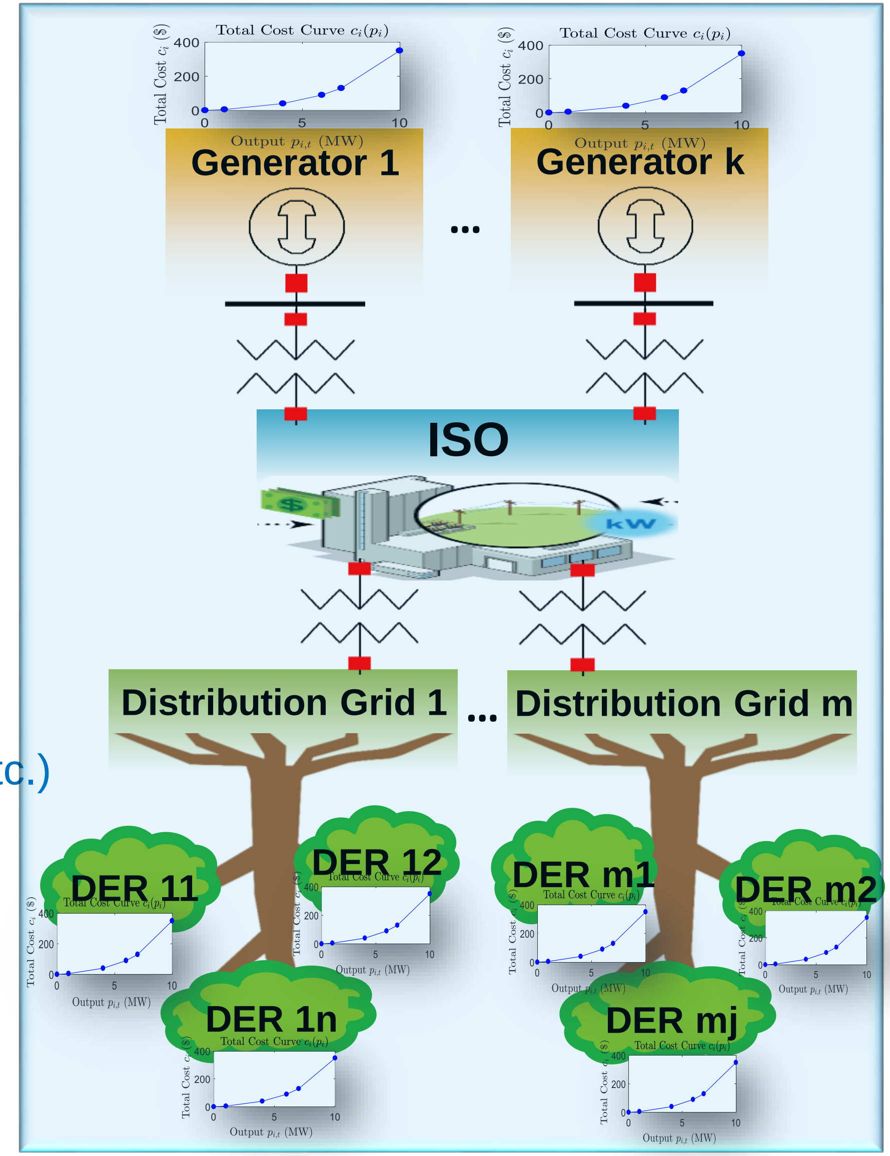
$$\min_{\boldsymbol{p}} \sum_{i\in\mathcal{N}^{Gen}\cup\mathcal{N}^{DER}} \boxed{c_i(p_i)}$$ → Minimize system generation cost

s.t. $\boldsymbol{p} \in \mathcal{S}^{ISO}$ → T-level operating constraints (load balancing, congestions, etc.)

$\boldsymbol{p} \in \mathcal{S}^{DSO_k}, \quad \forall k \in \mathcal{N}^{DSO}$ → D-level operating constraints for each D grid (load balancing, congestions, etc.)

$p_i \in \mathcal{S}_i^{Gen}, \quad \forall i \in \mathcal{N}^{Gen}$ → Generator operating constraints

$p_j \in \mathcal{S}_j^{DER}, \quad \forall j \in \mathcal{N}^{DER}$ → DER operating constraints

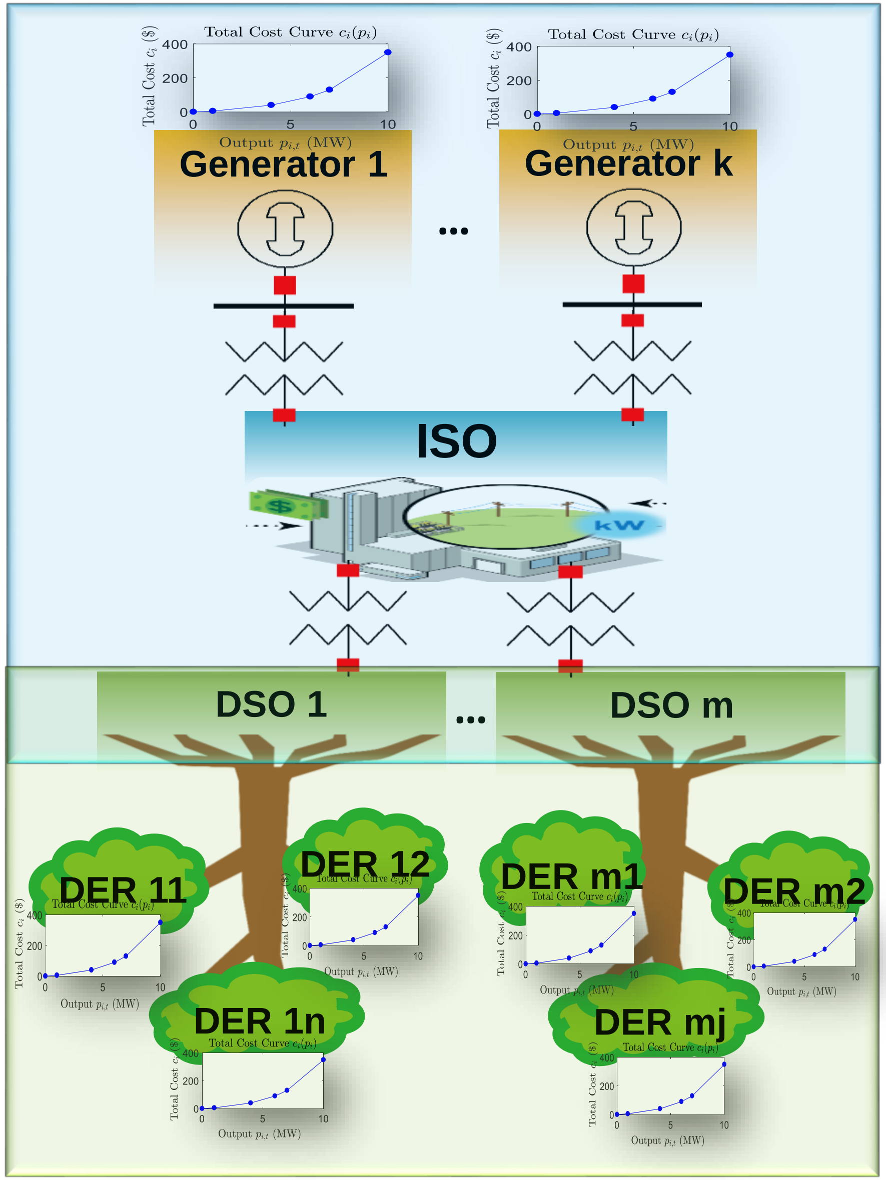


Optimal Decisions: Generator/DER dispatch outputs $\boldsymbol{p}$ (MW), locational marginal prices (\$/MWh)

T&D Coordination for DER Market Integration

Existing works for T&D market coordination:

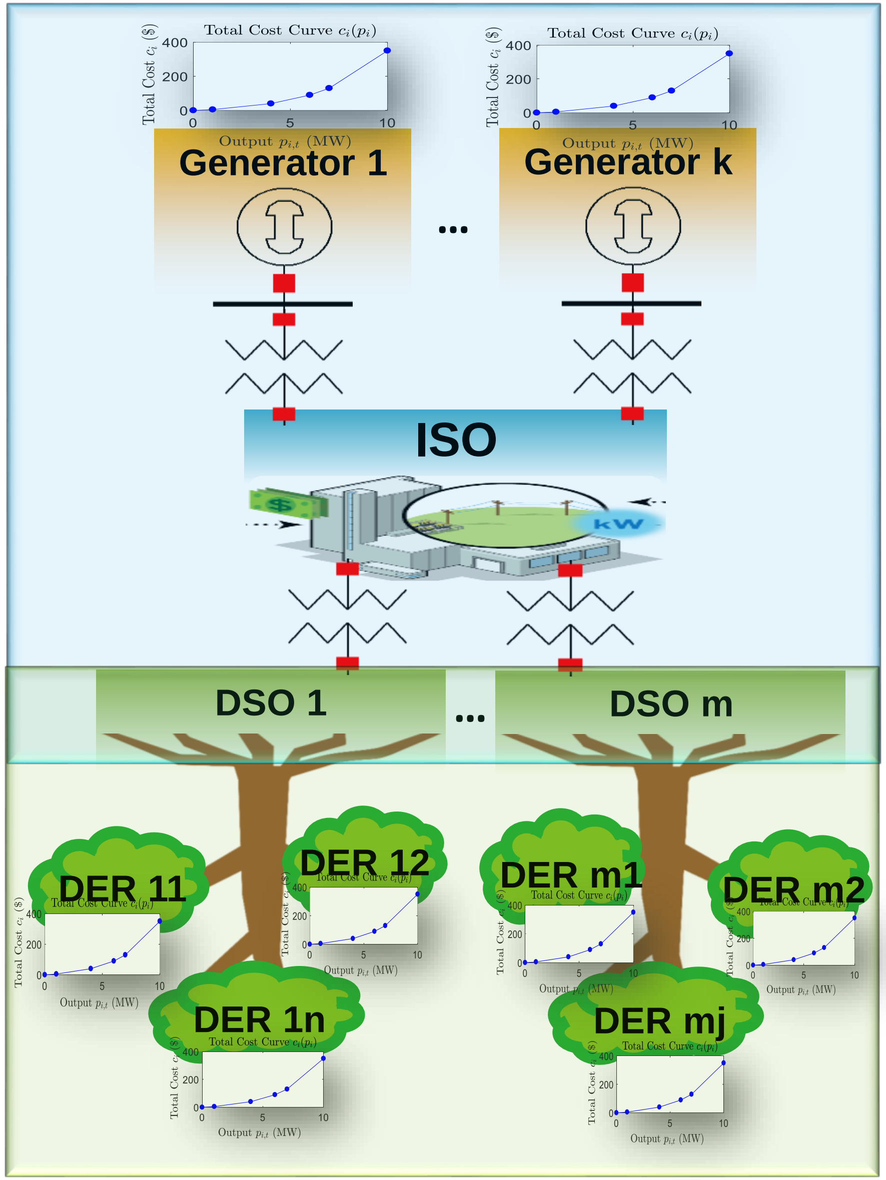
- ISO and DSOs to operate T&D markets separately
- Bi-level modeling, feasible region projection, multi-port power exchange
  - ✓ Exchanging T&D grid models/data → data confidentiality/privacy, increased ISO modeling/computation efforts
- Decentralized/Distributed optimization
  - ✓ Decompose the ideal (unrealistic) optimization model/computation across the ISO and DSOs
  - ✓ Coupled T&D iterative optimization solution process, exchanging T&D intermediate values during iterations
  - ✓ Need to change existing ISO market clearing computations
  - ✓ High communication demands between T&D



T&D Coordination for DER Market Integration

Proposed T&D market coordination:

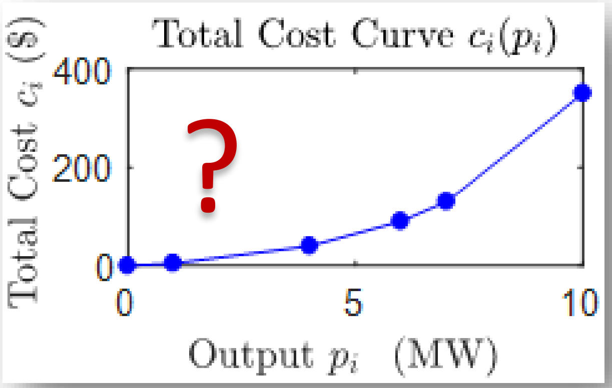
- ISO and DSOs to operate T&D markets separately
- Decompose the ideal (unrealistic) optimization model/computation across the ISO and DSOs
  - ✓ No T&D grid models/data exchange
  - ✓ No change to existing ISO market clearing procedure
  - ✓ Completely decoupled T&D solution iterations → no iterative T&D communications
  - ✓ Only exchange the minimal amount of public data → minimized communication burden between T&D
  - ✓ Decomposed T&D market clearing outcomes are identical to the ideal integrated market clearing outcomes.



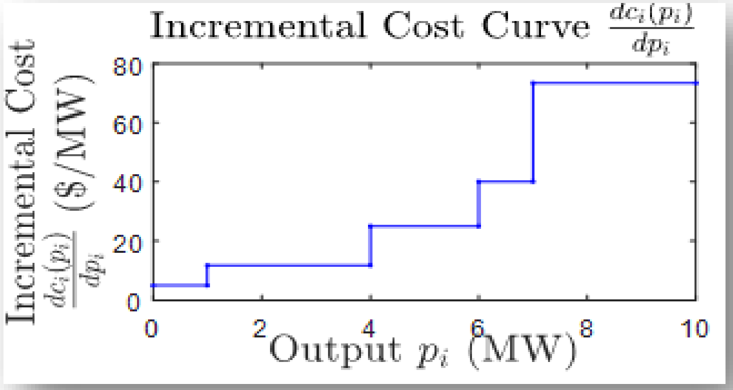
T&D Coordination for DER Market Integration

Proposed T&D market coordination:

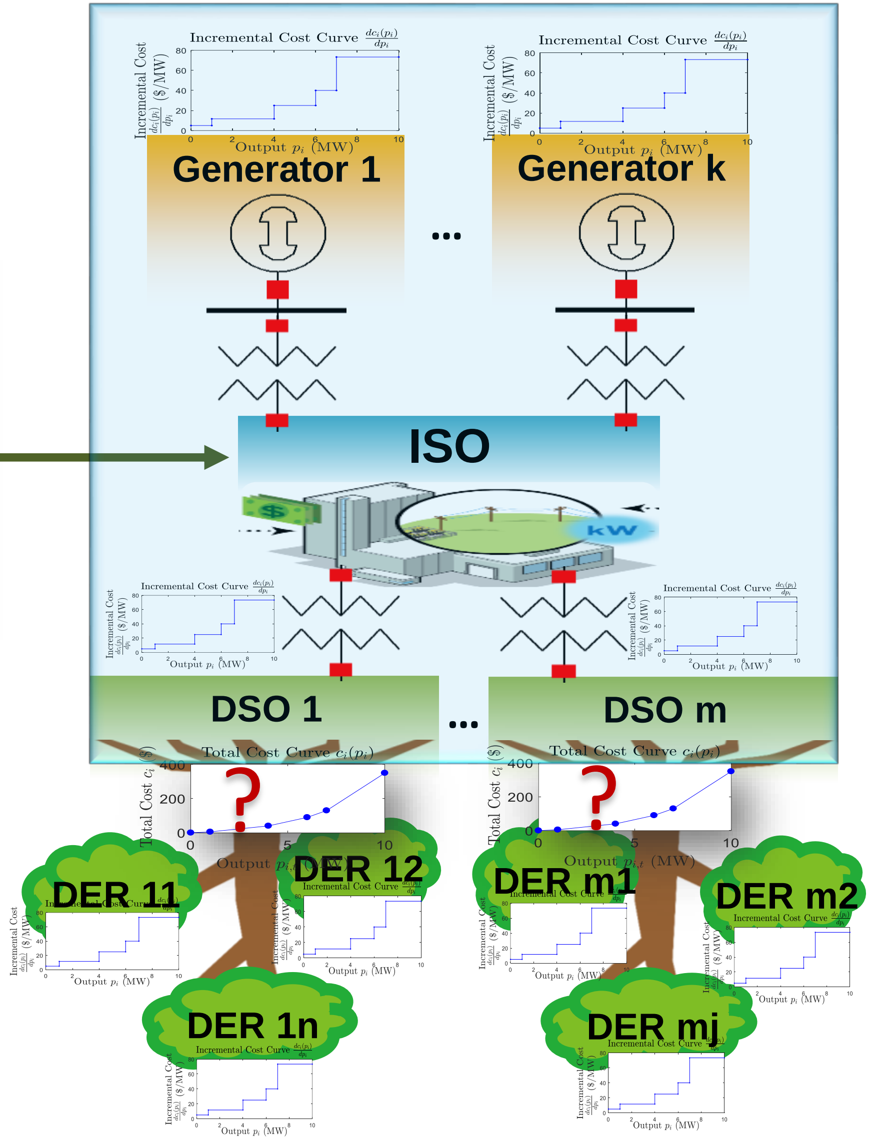
- ISO requests the incremental cost curves from all generators and DSOs



Total generation cost curve $c_i(p_i)$ submitted by i^{th} DSO



Incremental/Marginal generation cost curve $\frac{dc_i(p_i)}{dp_i}$ submitted by i^{th} DSO

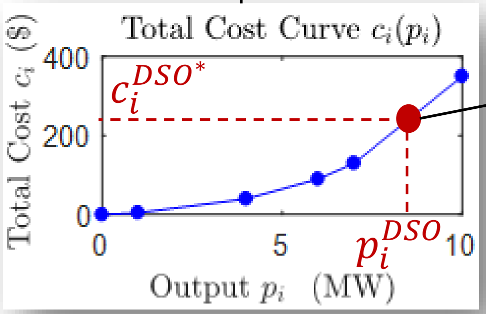


- DSO obtains its total generation cost curve (converted to the DSO incremental cost curve), after collecting incremental cost curves from all the (aggregated) DERs in the DSO territory → How?

T&D Coordination for DER Market Integration

Proposed T&D market coordination:

DSO cost curve submitted to ISO



Each point $(\boldsymbol{p_i^{DSO}}, \boldsymbol{c_i^{DSO*}})$ on this curve:

The true/lowest cost c_i^{DSO*} (\$) of generating p_i^{DSO} (MW) of real power from DSO to ISO

Total generation cost curve $c_i^{DSO}(p_i^{DSO})$ submitted by i^{th} (non-profit) DSO

Cost curves submitted by DERs to DSO

$$c_i^{DSO*}(p_i^{DSO}) = \min_{\mathbf{p}^{DER}} \sum_{j\in\mathcal{N}^{DER\,in\,DSO\,i}} c_j^{DER}(p_j^{DER})$$

Miniminal total generation costs of all DERs = true/lowest DSO generation cost c_i^{DSO*}

$$\text{s.t.} \quad \sum_{j\in\mathcal{N}^{DER\,in\,DSO\,i}} p_j^{DER} \geq p_i^{DSO}$$

Sum of all DER outputs ≥ Total DSO outputs p_i^{DSO}

$$\mathbf{p}^{DER} \in \mathcal{S}_i^{DSO}, \quad \forall i \in \mathcal{N}^{DSO}$$

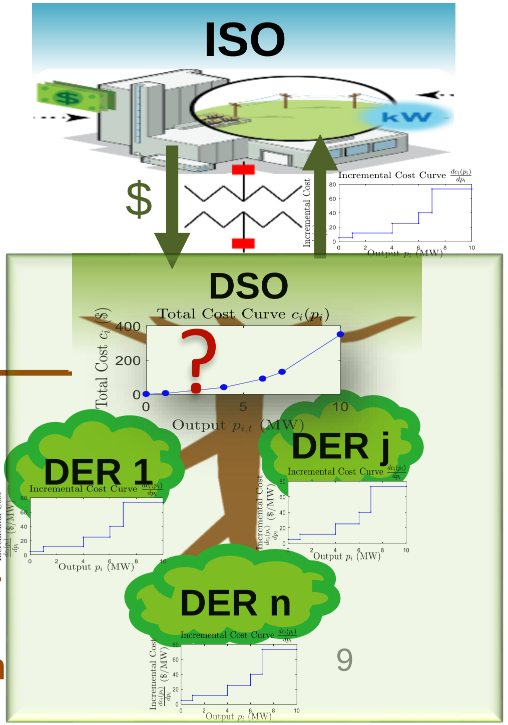
DSO operating constraints (voltage violations, congestions, load balancing)

$$p_j^{DER} \in \mathcal{S}_j^{DER}, \quad \forall j \in \mathcal{N}^{DER}$$

DER operating constraints (upper/lower power limits)

Optimal Decisions: DER dispatch outputs $\boldsymbol{p^{DER}}$ (MW), locational marginal prices

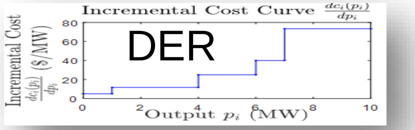
Inelastic load 1
⋮
Inelastic load m



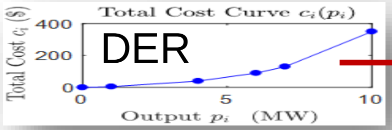
T&D Coordination for DER Market Integration

Proposed T&D market coordination (before ISO market clearing):

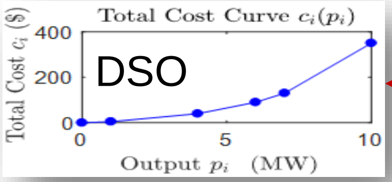
1. DSO collects incremental cost curve from each (aggregated) DER, $\frac{dc_j^{DER}(p_j^{DER})}{dp_j^{DER}}$



2. DSO constructs total cost curve for each (aggregated) DER, $c_j^{DER}(p_j^{DER})$



3. DSO runs parametric programming to obtain the DSO's total generation cost curve $c_i^{DSO}(p_i^{DSO})$ (true/lowest generation costs at all possible DSO generation levels)



$$c_i^{DSO*}(p_i^{DSO}) = \min_{\mathbf{p}^{DER}} \sum_{j \in \mathcal{N}^{DER\,in\,DSO\,i}} c_j^{DER}(p_j^{DER})$$

$$\text{s.t.} \quad \sum_{j \in \mathcal{N}^{DER\,in\,DSO\,i}} p_j^{DER} \geq p_i^{DSO}$$

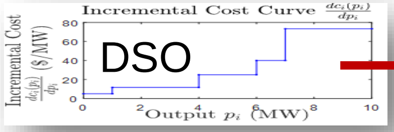
$$\mathbf{p}^{DER} \in \mathcal{S}_i^{DSO}, \quad \forall i \in \mathcal{N}^{DSO}$$

$$p_j^{DER} \in \mathcal{S}_j^{DER}, \quad \forall j \in \mathcal{N}^{DER}$$

DSO parametric programming

4. DSO converts the DSO's total generation cost curve $c_i^{DSO}(p_i^{DSO})$ to the DSO's incremental generation cost curve $\frac{dc_i^{DSO}(p_i^{DSO})}{dp_i^{DSO}}$

5. DSO submits the DSO's incremental generation cost curve $\frac{dc_i^{DSO}(p_i^{DSO})}{dp_i^{DSO}}$ to ISO



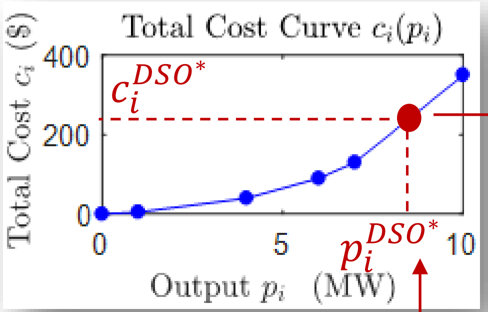
To ISO

T&D Coordination for DER Market Integration

Proposed T&D market coordination (after ISO market clearing):

1. ISO clears the wholesale market and sends out each DSO's wholesale dispatch signal $p_i^{DSO^*}$ (MW), wholesale locational marginal price (LMP) $\pi_i^{DSO^*}$ ($/MWh) → total wholesale payment to DSO = $p_i^{DSO^*} \times \lambda_i^{DSO^*}$ ($)

2. DSO re-dispatch the wholesale dispatch signal $p_i^{DSO^*}$ and wholesale payment $p_j^{DSO^*} \times \lambda_j^{DSO^*}$ to obtain the retail dispatch signal $p_j^{DER^*}$ and retail LMP $\lambda_j^{DER^*}$ for each DER



DSO's Optimal wholesale Dispatch signal $p_i^{DSO^*}$ (by ISO market clearing)

Optimal solution at $p_i^{DSO^*}$

DSO parametric programming

$$c_i^{DSO^*}(p_i^{DSO^*}) = \min_{\boldsymbol{p}^{DER}} \sum_{j \in \mathcal{N}^{DER\ in\ DSO\ i}} c_j^{DER}(p_j^{DER})$$

$$\text{s.t.} \quad \sum_{j \in \mathcal{N}^{DER\ in\ DSO\ i}} p_j^{DER} \geq p_i^{DSO^*}$$

$$\boldsymbol{p}^{DER} \in \mathcal{S}_i^{DSO}, \quad \forall i \in \mathcal{N}^{DSO}$$

$$p_j^{DER} \in \mathcal{S}_j^{DER}, \quad \forall j \in \mathcal{N}^{DER}$$

At DSO's wholesale dispatch signal $p_i^{DSO^*}$ → Optimal retail dispatch signal for each DER:

$$\boldsymbol{p}^{DER^*} = [p_1^{DER^*}, \ldots, p_j^{DER^*}, \ldots, p_n^{DER^*}]$$

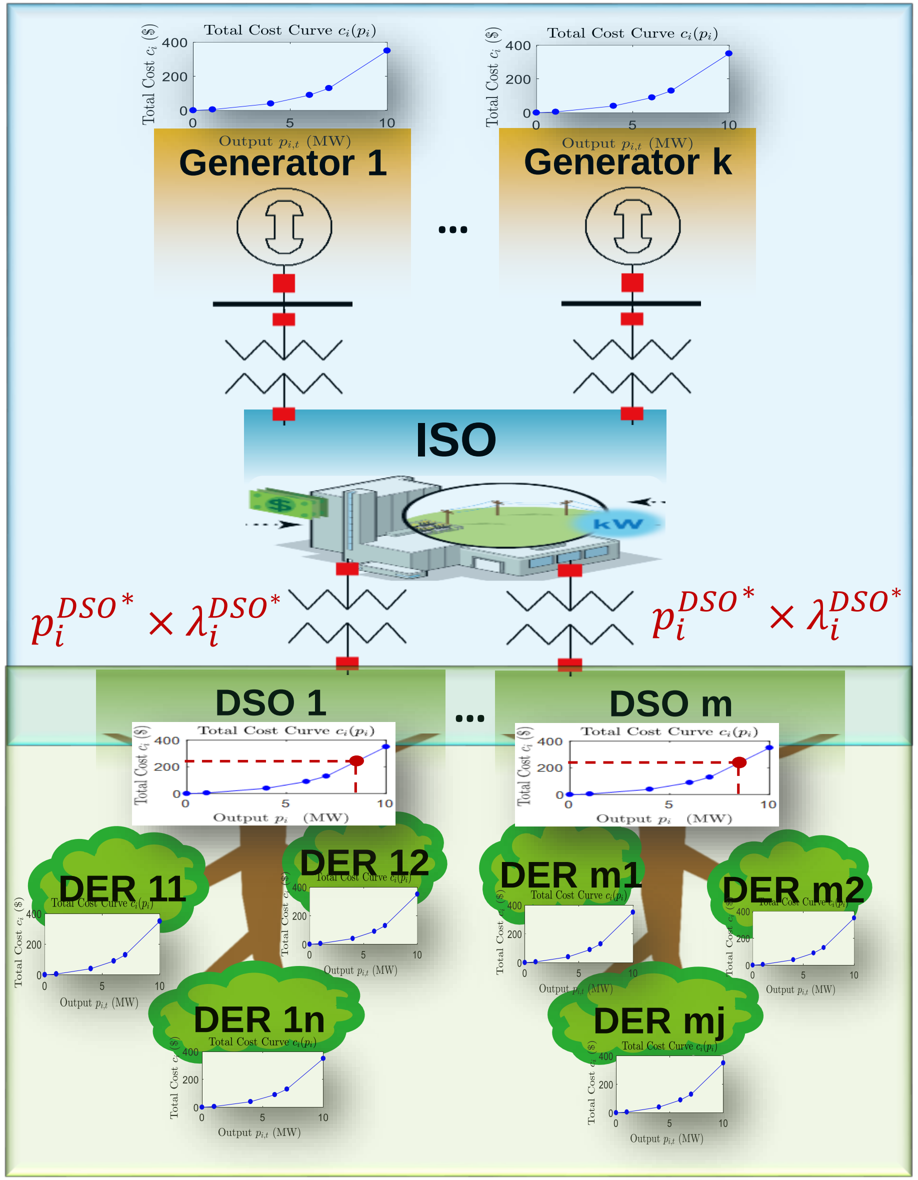
At DSO's wholesale dispatch signal $p_i^{DSO^*}$ → Optimal retail LMP for each DER:

$$\boldsymbol{\lambda}^{DER^*} = [\lambda_1^{DER^*}, \ldots, \lambda_j^{DER^*}, \ldots, \lambda_n^{DER^*}]$$

T&D Coordination for DER Market Integration

Proposed T&D market coordination:

- ISO and DSOs to operate T&D markets separately
  - ✓ Only exchange the minimal amount of public data:
    - DSO to ISO: DSO's incremental cost curve
    - ISO to DSO: DSO's wholesale dispatch and LMP
  - ✓ No change to existing ISO market clearing procedure
  - ✓ No iterative T&D communications
  - ✓ Decomposed T&D market clearing outcomes are identical to the ideal integrated market clearing outcomes.
    - DER dispatch and payment are identical in both markets
    - DSO will not lose money (DSO wholesale payment from ISO $\geq$ DSO total retail payment to DERs)



- M. Mousavi, and M. Wu, 'ISO and DSO coordination: a parametric programming approach'. Accepted to 2022 IEEE PES General Meeting. Available: https://arxiv.org/abs/2201.07433

T&D Coordination for DER Market Integration

Case studies – test case description:

- **ISO**: 3 generating units, 3 demand response units, 5MW firm load
- **DSO**: 10 nodes, 9 lines, 4 dispatchable distributed generation aggregators (DDGAG), 1 renewable energy aggregators (REAG), 1 demand response aggregator (DRAG)

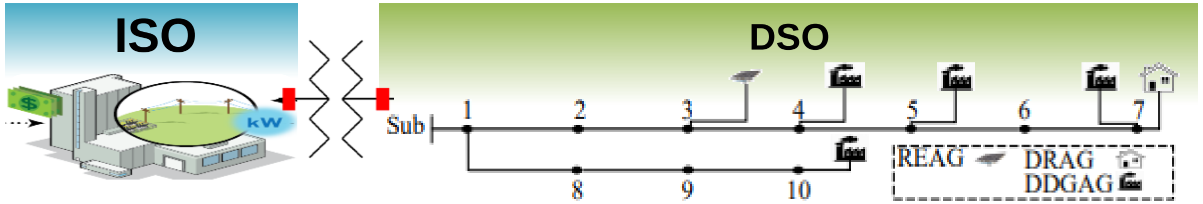


TABLE I
WHOLESALE MARKET PARTICIPANTS INFORMATION

Participant	Pmin (MW)	Pmax (MW)	Offering price ($/MWh)
Gen 1	0	10	8
Gen 2	0	20	20
Gen 3	0	30	22
DR 1	0	10	30
DR 2	0	20	32
DR 3	0	20	34

TABLE II
DSO MARKET PARTICIPANTS INFORMATION

Participant	Pmin (MW)	Pmax (MW)	Offering price ($/MWh)
DDGAG 1	0	0.5	20
DDGAG 2	0	1	10
DDGAG 3	0	1.2	15
DDGAG 4	0	2	24
DRAG	0	20	28
REAG	0	1	0

T&D Coordination for DER Market Integration

Case studies – DSO cost curves:

- **DSO**: parametric programming with linearized real/reactive power flow, voltage constraints, line flow constraints

$$\boxed{c^{dso}(P^{dso})} = Min \sum_{g\in G}\sum_{b\in B} P_{g,b}\pi_{g,b} - \sum_{d\in D}\sum_{b\in B} P_{d,b}\pi_{d,b} \quad (6)$$

s.t.

$$\sum_{d\in D}\sum_{b\in B} H_{n,d}P_{d,b} + H_n^{sub}\boxed{P^{dso}} + L_n^P - \sum_{g\in G}\sum_{b\in B} H_{n,g}P_{g,b} + \sum_{j\in J} Pl_j A_{j,n} = 0; \quad \forall n \in N \quad (7)$$

$$\sum_{d\in D}\sum_{b\in B} H_{n,d}P_{d,b}tan\phi_d + H_n^{sub}Q^{dso} + L_n^Q - \sum_{g\in G}\sum_{b\in B} H_{n,g}P_{g,b}tan\phi_g + \sum_{j\in J} Ql_j A_{j,n} = 0; \forall n \in N \quad (8)$$

$$0 \le P_{g,b} \le P_{b,g}^{max}; \quad \forall b \in B, \forall g \in G \quad (9)$$

$$0 \le P_{d,b} \le P_{d,g}^{max}; \quad \forall b \in B, \forall d \in D \quad (10)$$

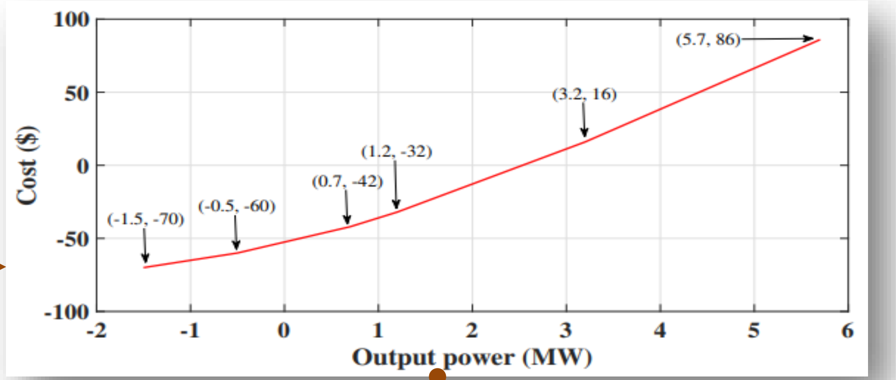
$$U_m = U_n - 2(r_j Pl_j + x_j Ql_j); \quad \forall m \in N, \quad \forall n \in N, \; C(m,n) = 1, \; A(j,n) = 1 \quad (11)$$

$$\underline{U} \le U_n \le \overline{U}; \quad \forall n \in N \quad (12)$$

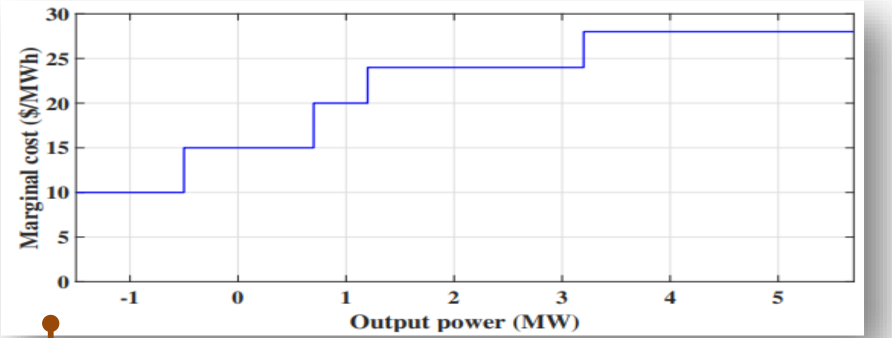
$$-Pl^{max} \le Pl_j \le Pl^{max}; \quad \forall j \in J \quad (13)$$

$$-Ql^{max} \le Ql_j \le Ql^{max}; \quad \forall j \in J \quad (14)$$

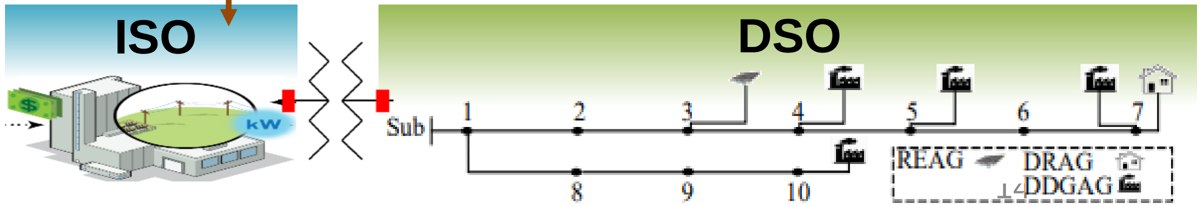
DSO total (minimal) generation cost



DSO incremental cost (price-quantity pairs)



Submitted to ISO



T&D Coordination for DER Market Integration

Case studies – market clearing outcomes:

TABLE III
ISO MARKET OUTCOMES IN THE IDEAL CASE. SHARE IS IN MW AND PAYMENT IS IN $

Name	Share	Payment	Name	Share	Payment
Gen 1	10	220	DDGAG 1	0.5	11
Gen 2	20	440	DDGAG 2	1	22
Gen 3	13.8	303.6	DDGAG 3	1.2	26.4
DR 1	-10	-220	DDGAG 4	0	0
DR 2	-20	-440	DRAG	-2.5	-55
DR 3	-10	-220	REAG	1	22

ISO

TABLE IV
ISO MARKET OUTCOMES IN THE ISO-DSO COORDINATION CASE. SHARE IS IN MW AND PAYMENT IS IN $

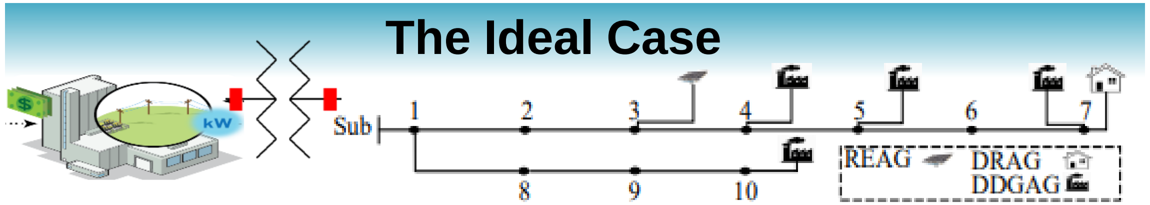
Participant	Share	Payment	Participant	Share	Payment
Gen 1	10	220	DR 1	-10	-220
Gen 2	20	440	DR 2	-20	-440
Gen 3	13.8	303.6	DR 3	-10	-220
DSO	1.2	26.4			

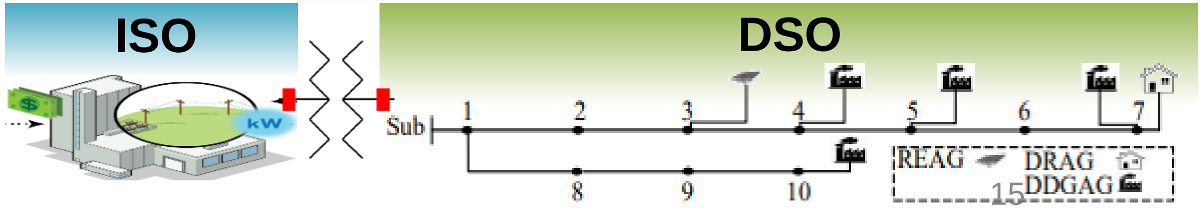
DSO

TABLE V
DSO MARKET OUTCOMES IN THE ISO-DSO COORDINATION CASE. SHARE IS IN MW AND PAYMENT IS IN $

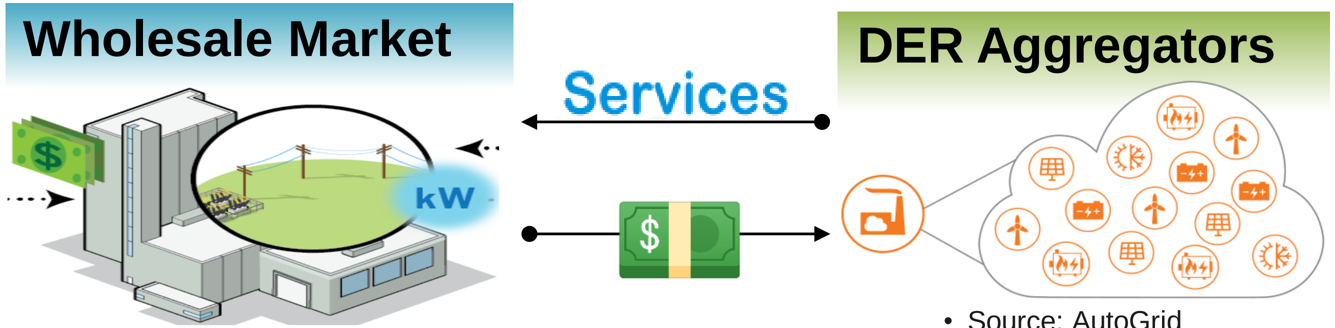
Participant	Share	Payment	Participant	Share	Payment
DDGAG 1	0.5	11	DDGAG 3	1.2	26.4
DDGAG 2	1	22	DDGAG 4	0	0
DRAG	-2.5	-55	REAG	1	22

- ISO-DSO market clearing price = 22$/MWh





Challenges & Opportunities



- Source: PJM
- Source: AutoGrid

Market Operation

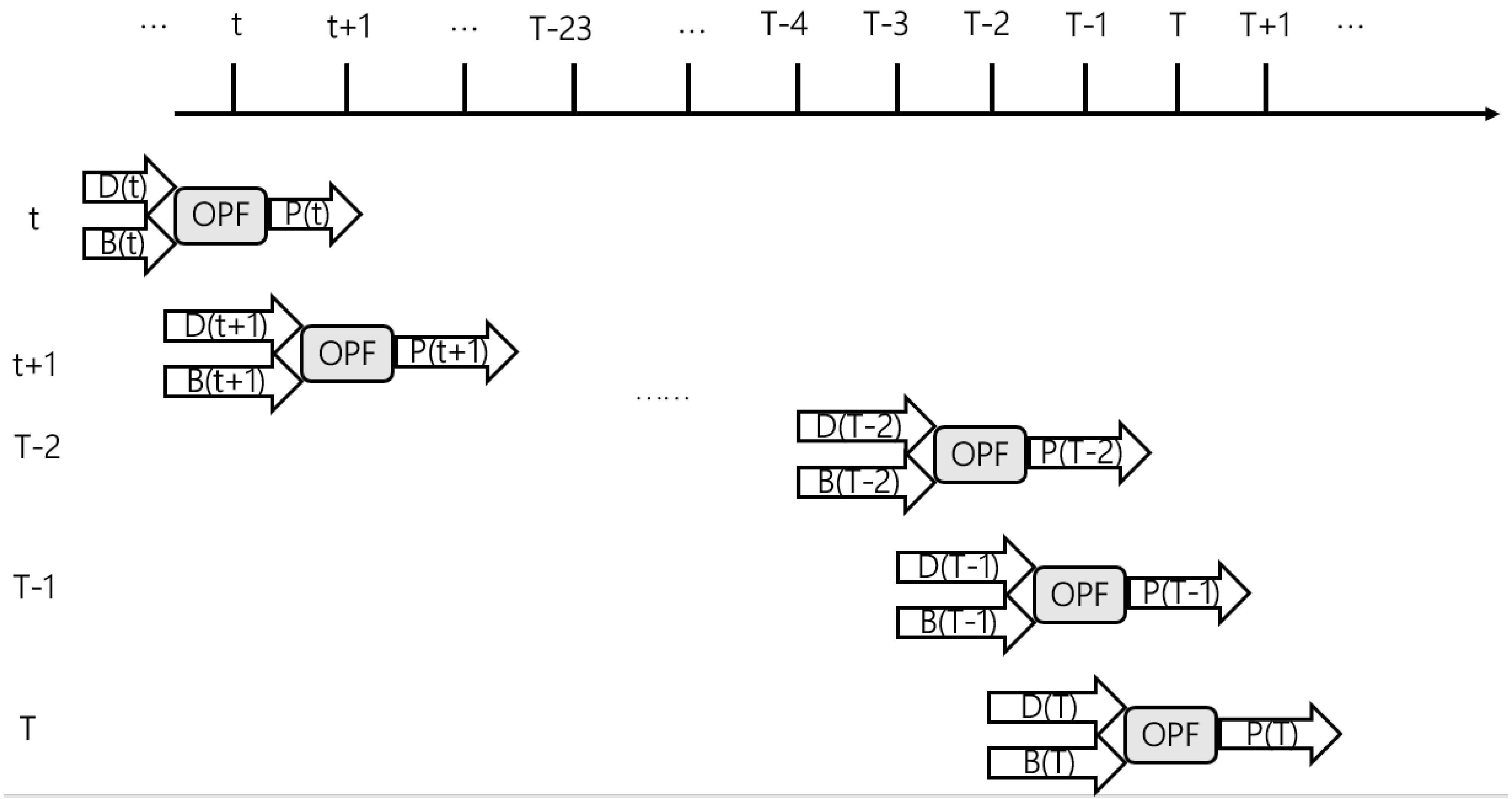
- Coordinate T&D, DER aggregators, and DERs?

Market Participation

- Forecast Electricity price?

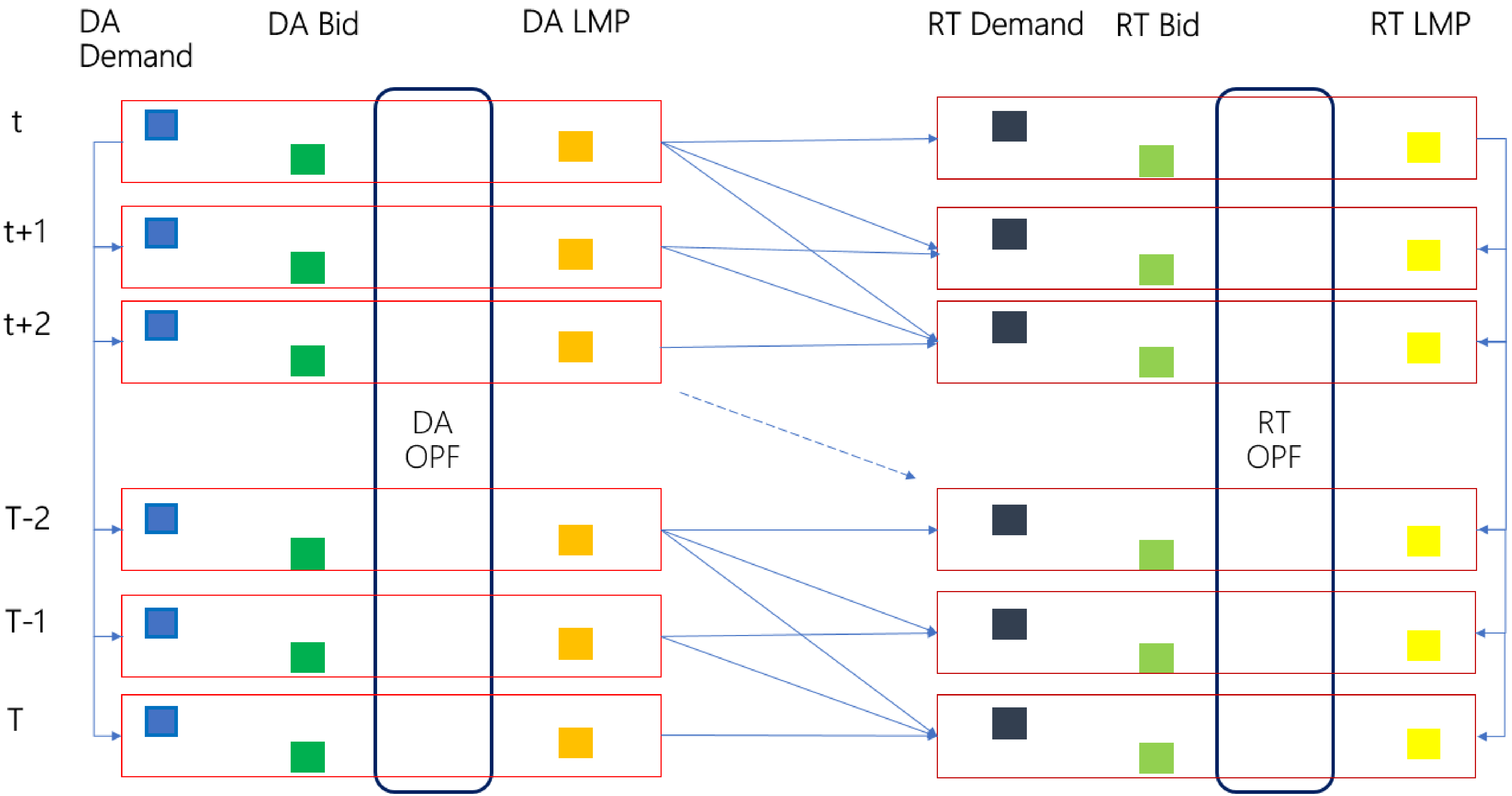
Electricity Price Forecasting using Decision Transformer

Motivation: Market Timeline



Electricity Price Forecasting using Decision Transformer

Market Timeline



Electricity Price Forecasting using Decision Transformer

Describe Electricity Market at T from Market Participants' Perspective

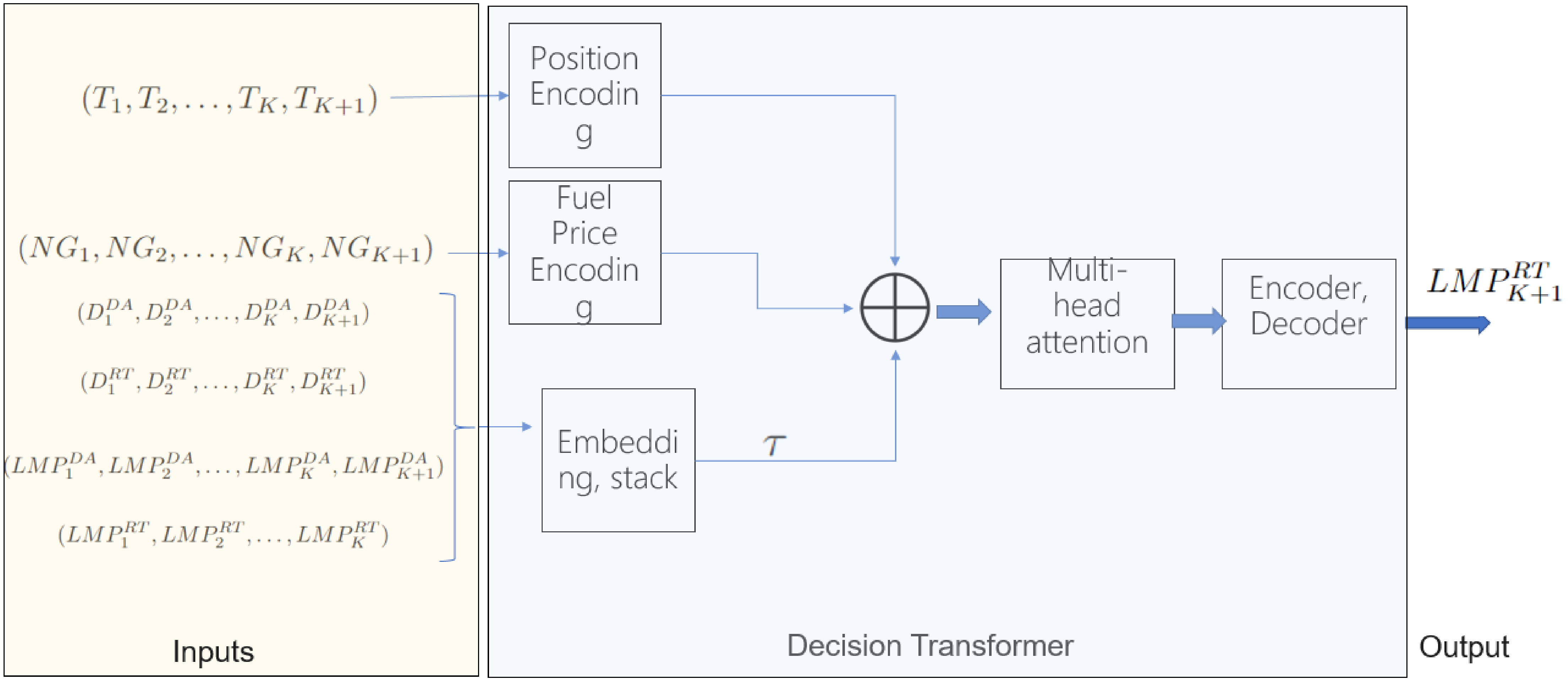
- Electricity market at t can be described by the tuple (D^{RT}_T, D^{DA}_T, LMP^{RT}_T, LMP^{DA}_T).
- For RT market, the RT OPF process can be represented by the transition dynamics: $P(LMP^{RT}_T | D^{RT}_T, B^{RT}_T)$.
- The generators' bidding strategy B^{RT}_T is a decision made based on previous states and current states: $P(B^{RT}_T | D^{RT}_{1\sim T}, D^{DA}_{1\sim T}, LMP^{RT}_{1\sim T-1}, LMP^{DA}_{1\sim T})$.
- Without knowledge of bidding data, the learning goal is to learn the RT OPF process denoted by: $P(LMP^{RT}_T | D^{RT}_{1\sim T}, D^{DA}_{1\sim T}, LMP^{RT}_{1\sim T-1}, LMP^{DA}_{1\sim T})$.
- Because $D^{RT}_{1\sim T}$, $D^{DA}_{1\sim T}$, $LMP^{RT}_{1\sim T-1}$, $LMP^{DA}_{1\sim T}$ are time series, the same data at different timesteps contribute differently, their positions in this time sequence should be utilited as conditional information.
- The generators' bidding strategy B^{RT}_T is also conditioned on fuel prices, which should also be utilized.

$$\tau = (D_1^{DA}, D_1^{RT}, LMP_1^{DA}, LMP_1^{RT}, D_2^{DA}, D_2^{RT}, LMP_2^{DA}, LMP_2^{RT}, \ldots, D_T^{DA}, D_T^{RT}, LMP_T^{DA}, LMP_T^{RT})$$

Trajectory representation

Electricity Price Forecasting using Decision Transformer

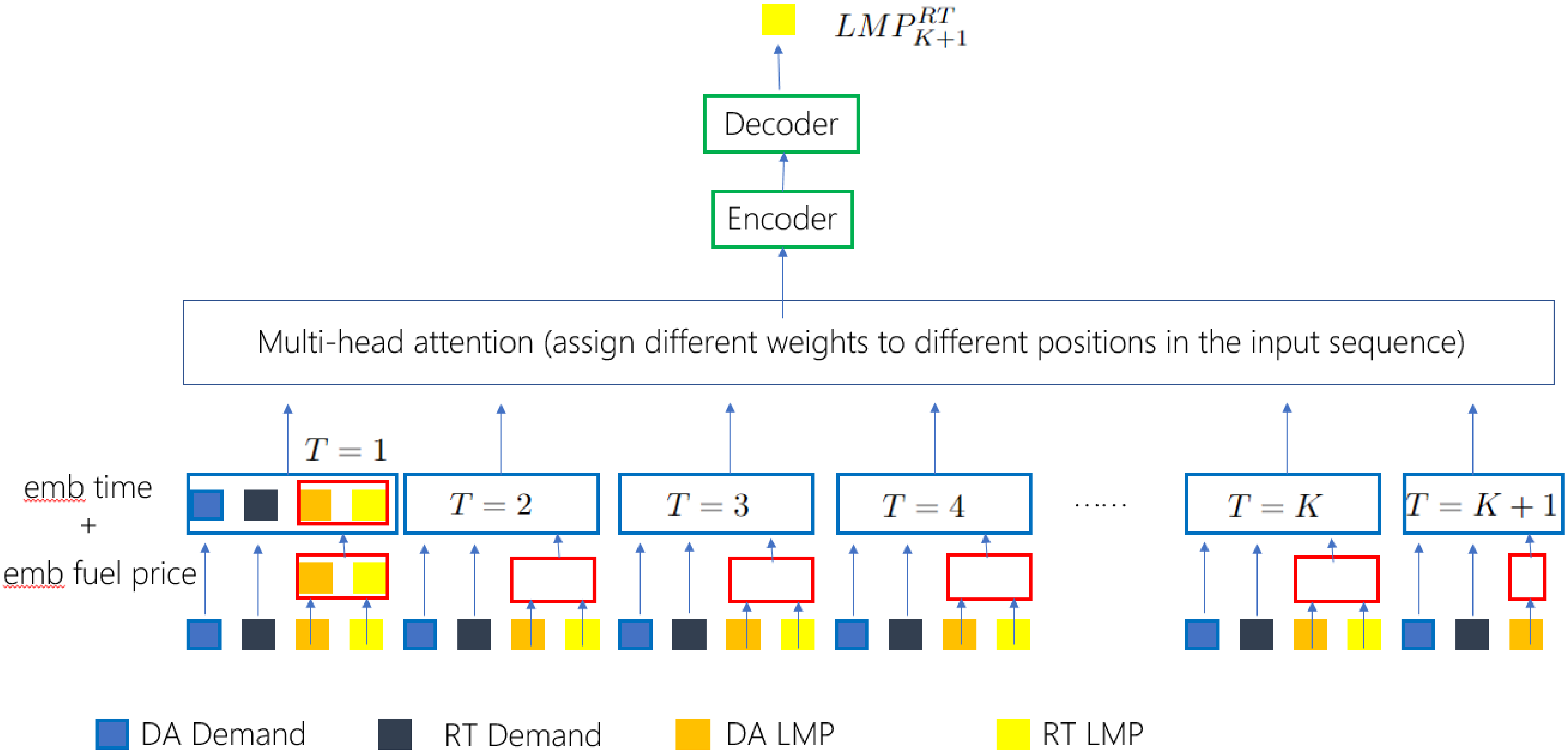
The Structure of Decision Transformer Predictor



$$\tau = (D_1^{DA}, D_1^{RT}, LMP_1^{DA}, LMP_1^{RT}, D_2^{DA}, D_2^{RT}, LMP_2^{DA}, LMP_2^{RT}, \ldots, D_{K+1}^{DA}, D_{K+1}^{RT}, LMP_{K+1}^{DA})$$

Electricity Price Forecasting using Decision Transformer

The Architecture of Decision Transformer

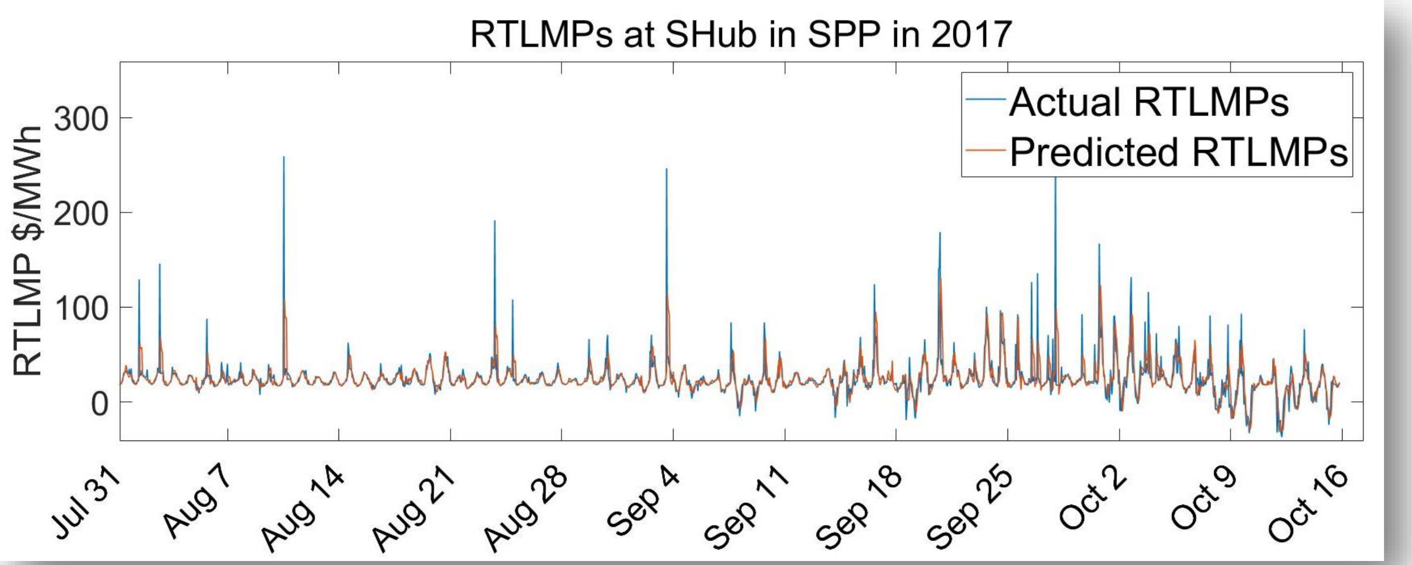


Electricity Price Forecasting using Decision Transformer

Case studies – Southwest Power Pool:

- **Training Data:** Hourly zonal RTLMPs, DALMPs, RT demand, DA demand, and natural gas prices from 6/1/2016 to 7/30/2017 in SPP. Additional historical generation mix data is incorporated.

- **Testing Data:** Predicting hourly SPP RTLMPs for Shub and Nhub price zone in the following periods: 7/31/2017-8/13/2017, 8/21/2017-9/3/2017, 9/18/2017-10/1/2017, and 10/2/2017-10/15/2017.



The decision transformer model is tested to predict hourly RTLMPs:

(A): in the hour-ahead manner

(B): in the day-ahead manner

Electricity Price Forecasting using Decision Transformer

Case studies – Southwest Power Pool:

- **Training Data:** Hourly zonal RTLMPs, DALMPs, RT demand, DA demand, and natural gas prices from 6/1/2016 to 7/30/2017 in SPP. Additional historical generation mix data is incorporated.

- **Testing Data:** Predicting hourly SPP RTLMPs for Shub and Nhub price zone in the following periods: 7/31/2017-8/13/2017, 8/21/2017-9/3/2017, 9/18/2017-10/1/2017, and 10/2/2017-10/15/2017.

RTLMP Prediction Accuracy in Case 1 (B)

Approach	MAPE (%) for SHub Price Zone
NN	59.2
MARS	51.8
ARMA	37.4
SVM	40.9
LASSO	33.5
ALG+$\hat{M}$[1]	25.4
Genscape[2]	21.7
GAN	22.1
Case 2 (A)	21.0
Case 2 (A) without natural gas price	21.9

[1] The proposed method with the best performance in [1]
[2] State-of-the-art baseline prediction from Genscape [1]

The decision transformer model is tested to predict hourly RTLMPs:

(A): in the hour-ahead manner

(B): in the day-ahead manner

Electricity Price Forecasting using Decision Transformer

Case studies – ISO New England:

- **Training Data:** Hourly zonal RTLMPs, DALMPs, RT demands, and DA demands and historical natural gas prices from January 2019 to September 2019 in ISO-NE.

- **Testing Data:** Predicting hourly ISO-NE RTLMPs hour by hour from October 2019 to December 2019.

RTLMP Forecasting Accuracy in Cases 2

Approach	MAPE (%) in Case 2(A)	MAPE (%) in Case 2(B)	MAPE (%) in Case 2(C)
NN	37.2	34.8	33.1
ARMA	30.7	25.1	26.3
SVM	27.7	25.2	25.6
CLSTM-GAN	15.4	12.09	13.1
DT	12.9	10.8	10.5

The decision transformer model is tested to predict next hour RTLMPs:

(A): using past 12-hour historical data

(B): using past 24-hour historical data

(C): using past 48-hour historical data

Future Directions

T&D coordination for DER market integration

- Extend the proposed approach to energy + reserve markets
- Consider resources with inter-temporal constraints (such as batteries)
- Consider binary decisions (such as unit commitment)
- Coordinate distribution-level services with transmission-level services
- Computationally efficiently algorithms for the parametric-programming-based retail market

Machine learning for market analysis/prediction

- Analyze market participant behavior
- Pricing design

Toward Future Electricity Markets with Massive DER Penetration and Optimal Transmission-Distribution Coordination

Meng Wu
Arizona State University
(mwu@asu.edu)