

Power generation characteristics of vertical bifacial photovoltaic arrays in heavy snow regions

Shuto Tsuchida^{1,*}, Yuki Tsuno², Daisuke Sato³, Takashi Oozeki², and Noboru Yamada¹

¹ Department of Science of Technology Innovation, Nagaoka University of Technology, Nagaoka 940-2188, Japan

² Fukushima Renewable Energy Institute (FREIA), National Institute of Advanced Industrial Science and Technology (AIST), Koriyama 963-0298, Japan

³ Department of System Safety Engineering, Nagaoka University of Technology, Nagaoka 940-2188, Japan

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Abstract. Conventional tilted photovoltaic systems often experience reduced electricity generation and potential damage due to snow accumulation. In contrast, vertical bifacial photovoltaic systems demonstrate greater resilience against snow-related damage, making them particularly suitable for snowy regions. This study explores the electricity generation characteristics of vertical bifacial photovoltaic systems in areas where snow depths exceed 1 meter, through both experimental and simulation analyses. Experiments conducted on a vertical bifacial system over two winter seasons showed no signs of damage or breakage. Additionally, during snowy periods, the power generation ratio relative to global horizontal irradiance increased by 55%, primarily due to irradiance reflected from the snow surface. However, this gain was offset by a 17% decrease due to partial shading by snow. Furthermore, integrating ray tracing with electrical circuit analysis revealed that implementing separate maximum power point tracking for the upper and lower sections of a single-row vertical bifacial photovoltaic array could alleviate losses in electricity generation caused by deep snow covering the photovoltaic cells. This study advances our understanding of the impact of snow on the power generation of vertical bifacial photovoltaic systems in heavy-snow regions and is expected to contribute to the development of more efficient designs in the future.

Keywords: Bifacial PV module / heavy snow region / partial shading / mismatch loss / ray tracing

1 Introduction

Bifacial photovoltaic (PV) systems have significantly advanced in terms of cost-effectiveness and are becoming increasingly dominant in the PV technology landscape. Projections indicate that bifacial PV modules will secure approximately 70% of the market share by 2033 [1]. These systems are capable of generating more power per unit area compared to monofacial PV systems by harnessing sunlight that strikes both the front and rear surfaces of the modules [2,3]. A considerable body of research has been dedicated to estimating the electricity yield of bifacial PV systems [4–8]. For example, Yusufoglu et al. [4] analyzed the impact of factors such as installation location and ground surface reflectance (albedo) on the optimal tilt angle of an array through an analysis of rear-side irradiance. Rouholamini et al. [7] developed an incident energy-based model for bifacial PV arrays, considering variables including albedo,

tilt and azimuth angles, height above the ground, and horizontal distance between arrays. They found that properly configured bifacial systems could increase annual energy generation by up to 31% compared to monofacial systems in Detroit, USA (latitude 42°N).

In recent years, vertical bifacial PV systems have emerged as practical alternatives for enhancing electricity generation and optimizing land use. With appropriate system design, vertical bifacial PV systems can outperform tilted monofacial PV systems, particularly in high-latitude regions or environments with high albedo. Guo et al. [9] highlighted that the superior performance of vertical bifacial PV systems over tilted monofacial systems primarily depends on factors such as latitude, diffuse fraction, and albedo. Khan et al. [10] reported that vertical bifacial PV systems generated 10–20% more energy than tilted monofacial systems when installed with a module height of 1.2 m and an array pitch of 2 m across most global regions. Rodríguez-Gallegos et al. [11] examined the cost-effectiveness of monofacial and bifacial PV systems across 55 locations worldwide, concluding that vertical bifacial

* e-mail: s193059@stn.nagaokaut.ac.jp

PV systems were economically advantageous at latitudes above 65° compared to monofacial PV systems. Below 65° latitude, vertical bifacial systems may demonstrate superiority provided suitable albedo values are maintained. Shigenobu et al. [12] demonstrated that vertical bifacial PV systems could mitigate the mismatch between PV electricity generation during mornings and evenings and the demand. Jouttijärvi et al. [13] found that vertical bifacial PV systems were particularly beneficial at high latitudes due to efficient irradiation collection enabled by low average solar altitude angles.

Furthermore, vertical bifacial PV systems are under consideration for application in agrivoltaics due to their small footprint and compatibility with dual land use. Riaz et al. [14] reported that vertical bifacial PV farms produce equivalent energy output and photosynthetically active radiation (PAR) compared to conventional tilted monofacial PV farms when the PV array density is reduced by half or more relative to standard ground-mounted PV farms. They also noted that while combined PAR/energy yields for vertical bifacial PV may not consistently exceed those of monofacial PV, its advantages—including minimal land coverage, minimal interference with farm machinery and rainfall, inherent resilience to soiling, and ease of cleaning—make it attractive for agrivoltaics.

Additionally, vertical bifacial PV systems are well-suited for deployment in regions with heavy snowfall where snow accumulation on module surfaces is less likely. In such areas, the risk of PV system failure due to mechanical loading from snow accumulation is a significant concern for conventional tilted PV systems. Studies have indicated a potential for micro-cracks in solar cells [15] and possible damage or deformation of module frames [16] due to snow loads. According to research by Jordan et al. [17], snow depths exceeding one meter can lead to an increased performance loss rate (PLR)—permanent losses in the system—due to module damage from high snow loads. Moreover, power generation losses from snow and/or ice coverage on module surfaces are critical concerns in snowy regions. Experiments conducted in Edmonton, Canada (53°N) on monofacial PV systems have shown that small tilt angles result in increased snow accumulation on modules, leading to higher electricity generation losses [18]. Hayibo et al. [19] conducted simulation analyses based on observed snow coverage ratios in real systems in Escanaba, USA (45°N), and found that in the worst-case scenario, tilted monofacial PV systems incurred an annual electricity loss of 16% due to snow shading, compared to 2% for tilted bifacial PV systems, attributed to their lower snow coverage ratios. The tilt angle for both systems was 35° .

To the best of our knowledge, there are only a few comprehensive reports on vertical bifacial PV systems in snowy regions. Granlund et al. [20] conducted experiments in northern Sweden (65°N) using ten single bifacial PV modules installed at tilt angles ranging from 0° to 90° . Their findings indicated that modules installed horizontally accumulated the most snow, whereas those installed vertically accumulated the least. Molin et al. [21] investigated vertical bifacial PV arrays in Linköping, Sweden (58.4°N), to study the impact of high albedo from

snow in high-latitude regions. They observed that as albedo increased from 0.05 (April 11) to 0.8 (April 15), daily electricity generation per unit of daily solar irradiation increased by approximately 48%.

Although the snow depth in these studies appears relatively shallow, likely less than 0.1 m, and the experiments were conducted in high-latitude regions, they suggest the potential suitability of vertical bifacial PV systems under deeper snow conditions not only at high latitudes but also at mid-latitudes. Deeper snow may obscure the vertical PV array, reducing received irradiance. This partial shading can influence the current-voltage characteristics of the vertical PV array and the reflection of sunlight by snow, aspects that have not been thoroughly investigated. Therefore, understanding these characteristics is crucial for optimizing the design of vertical bifacial systems.

This study explores the power generation characteristics of vertical bifacial PV systems in regions where snow depths exceed 1 m, specifically in Nagaoka City, Japan ($37^\circ45'\text{N}$), through year-long experiments. The experimental results indicate that the vertical bifacial PV system did not exhibit observable damage due to snow accumulation. The study also reveals the effects of increasing snow depth and solar reflection on the current-voltage characteristics of vertical bifacial PV systems, utilizing measurements and optical-electrical circuit analysis. Furthermore, the study examines the impact of different electrical connections of the modules on power generation using an optical-electrical circuit model.

2 Methodology

2.1 Outdoor experiment

The vertical bifacial PV array used in this experiment is depicted in Figure 1a. Located at Nagaoka University of Technology ($37^\circ45'\text{N}$, $138^\circ85'\text{E}$), the installation site is characterized by heavy snowfall, with snow depths often exceeding 1 m. Throughout the study period's winter seasons, average temperatures and wind speeds were recorded at 3.6°C and 2.4 m/s , respectively [22]. On January 30, 2023, the snow depth reached approximately 1.2 m, as depicted in Figure 1b. The array comprised two rows of two landscape-oriented bifacial PV modules each (Kaneka, GRANSOLA D-P2255). Figure 1c illustrates the interconnections between modules. Each module consisted of 8×6 cells, measuring $1.36 \times 1.0\text{ m}^2$. Within each sub-string of 16 cells (shown in Fig. 1c), a bypass diode (BPD) was installed to prevent current backflow in cells affected by partial shading or uneven sunlight, thus mitigating potential hot spot phenomena. Each module was equipped with three BPDs. The bifaciality (φ), indicating the power generation efficiency ratio between the front and rear surfaces of the module, was 0.8 (catalog value). Specifications for the bifacial PV modules (catalog values) under standard testing conditions (STC), where only the front side is illuminated, are detailed in Table 1. The modules were oriented such that their front surfaces faced west and rear surfaces faced east, with the array's lower end positioned 0.5 m above the ground level. Adjacent to the

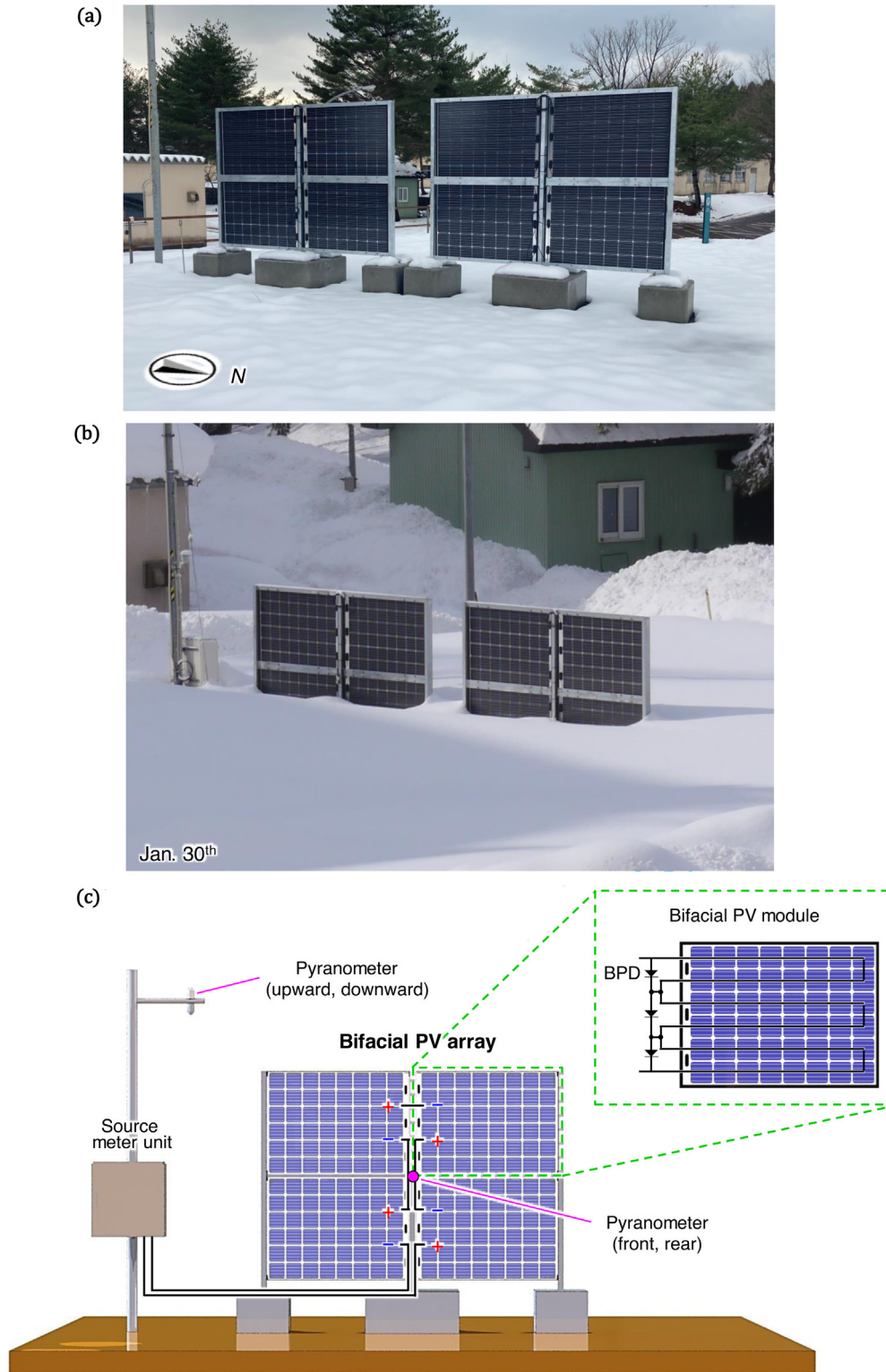


Fig. 1. (a) Vertical bifacial PV array in heavy snow region. (b) Vertical bifacial PV at highest snow accumulation. (c) Wiring diagram of PV array (four modules).

Table 1. Specifications of the bifacial PV module (STC).

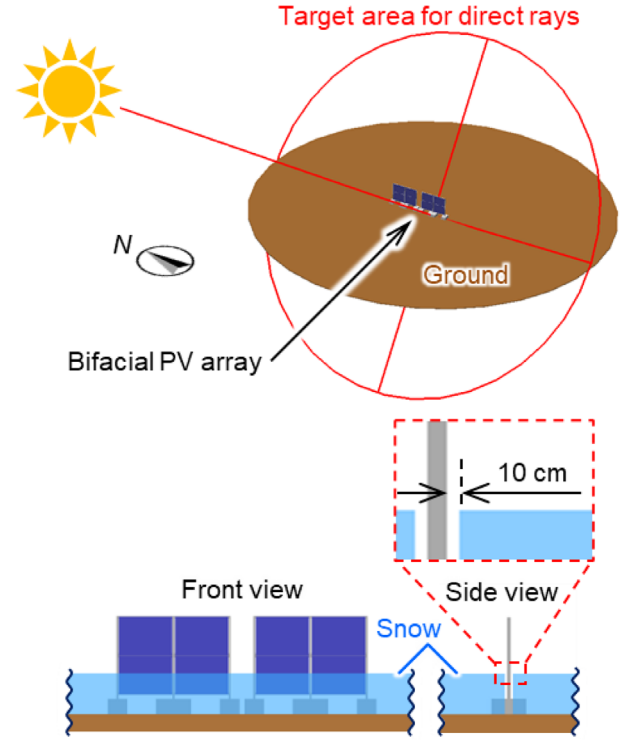
Solar cell type	Si hetero-junction
Maximum power ($P_{\max}$)	245 W
Maximum power voltage (V_{mp})	28.71 V
Maximum power current (I_{mp})	8.53 A
Open-circuit voltage (V_{oc})	35.23 V
Short-circuit current (I_{sc})	9.28 A
Area of the module	1.36 m ²
Number of solar cells	48
Bifaciality (ϕ)	0.8

array, support pillars held upward and downward facing pyranometers (Climatec, CHF-SR05) and a thermometer (T-type thermocouple) to measure horizontal global irradiance, ground-reflected irradiance, and air temperature, respectively. Additionally, west- and east-facing pyranometers (Eko instruments, ML-01) were centrally positioned within the array to measure plane of array (POA) irradiance on both the front and rear surfaces of the modules. Each array consisted of four modules, and current–voltage (I – V) curves were recorded at 10-minute intervals using a source meter unit (Nippon Kernel System, PV Scanner: PVSC11271, PV Analyzer Gamma: PVA11270, Measurement Unit: CMU12281). Data collection covered the period from May 1, 2022, to April 30, 2023, with the exception of power outages between December 30, 2022, and January 8, 2023 (ten days). Notably, the system has endured two winter seasons since its installation on November 15, 2021.

2.2 Simulation

2.2.1 Optical model

A commercial ray-tracing simulator, LightTools 9.1.1, was used to simulate irradiance on both sides of the PV modules. Ray tracing generally yields more accurate estimates of irradiance distribution compared to view-factor-based calculations, particularly for complex-shaped structures. **Figure 2** displays the simulation model of the experimental system. A snow accumulation simulation model was developed by manually inputting snow depth from periodic camera images, represented as a rectangular block. Observations throughout the snowy season indicated an average 10 cm gap between the snow and the module surface due to melting and shedding of snow in contact with the module. This observation informed the 10 cm gap parameter in the snow model, as depicted in the side view of **Figure 2**. Direct sunlight rays were emitted in straight lines from a disk-shaped light source at the sun's position onto the bifacial PV array at specified dates and times, accounting for the sun's angle of incidence. Diffuse sunlight rays were emitted isotropically from a hemispherical light source surrounding the array (not shown in **Fig. 2**). The Erbs model [23], which derives direct and diffuse irradiances, was applied to each light source using measured values of horizontal global irradiance. The

**Fig. 2.** Ray tracing simulation model of bifacial PV array.

simulation domain was defined within a 20-meter radius circle centered on the array. Preliminary simulations incrementally increased the ray count from 1 million to 2 billion. A comparison of results between 1 billion and 2 billion rays showed that the maximum local irradiance change at the PV array was only 0.2%. Consequently, 2 billion rays were selected for the simulations. The module frame reflectance was assumed to be 0.5, with a Lambertian surface. Cells within the module were assumed to be perfect absorbers. Albedo was determined using the ratio of average upward and downward pyranometer measurements. Ground and snow surface reflectance characteristics were also assumed to be Lambertian, with no consideration for wavelength dependence. Similar to this study, Tsuchida et al. [24] noted that assuming ground surfaces and module frames as Lambertian reflective surfaces effectively replicates the impact of partial shading caused by mounting structure beams and module frames on power output from tilted bifacial PV arrays with high-albedo ground cover.

2.2.2 Electrical model

An open-source software package, LTspice XVII, was employed for cell-level electrical circuit simulation. **Figure 3** depicts the equivalent circuit model of the bifacial PV module. The photogenerated currents in the cells on the front and rear sides, denoted as I_{front} and I_{rear} , respectively, were connected in parallel. Each cell contains a diode component, represented by D . R_s and R_{sh} denote series and shunt resistances of individual PV cells, set at 0.006 Ω and 100 Ω , respectively. Given the challenge of estimating

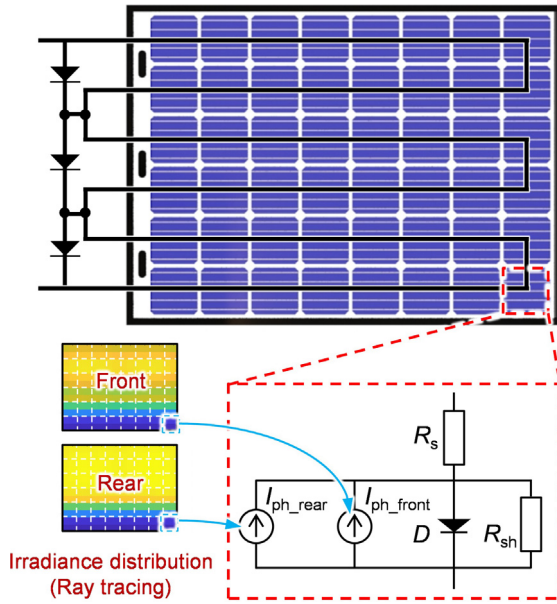


Fig. 3. Schematic of cell-level equivalent circuit model of the bifacial PV module and correlation between the simulated irradiance distributions.

convective heat transfer coefficients with a partially snow-buried vertical module, the PV cell's operating temperature was assumed to be constant, equivalent to the average daytime ambient temperature recorded during measurements. It should be noted that the temperature of a PV cell under illumination typically exceeds the ambient air temperature. This discrepancy can lead to an overestimation of PV power generation, as a PV cell exposed to illumination often operates at a higher temperature than the surrounding air due to reduced convective heat transfer from the cell to the ambient air. The module consists of three substrings, each incorporating BPDs connected in parallel, with 16 cells per substring arranged in series. The I - V curve of the module was computed using the simulated cell irradiance (I_{cell}) derived from ray tracing. I_{cell} was calculated using the following equation:

$$I_{\text{cell}} = I_{\text{front}} + I_{\text{rear}} = \frac{G_{\text{front}} + G_{\text{rear}} \cdot \varphi}{G_{\text{stc}}} I_{\text{sc_stc}}, \quad (1)$$

where G_{front} , G_{rear} , and G_{stc} are the front cell, rear cell, and cell irradiances at STC, respectively, and $I_{\text{sc_stc}}$ is the short-circuit current at STC, set to 9.28 A for the vertical bifacial PV module used in this experiment.

3 Experimental results

Figure 4 displays the monthly averages of daily accumulated power generation from May 2022 to April 2023, normalized by daily accumulated global horizontal irradiance (GHI), along with the monthly averages of snow depth (H_s). Data for periods without snow are shown in black, while periods with snow are indicated in red. During the snow-free months, the monthly average of daily

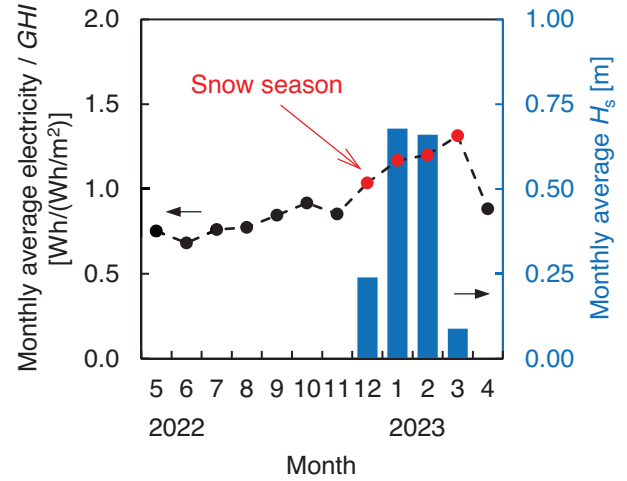


Fig. 4. Monthly average electricity/GHI and snow depth for each month.

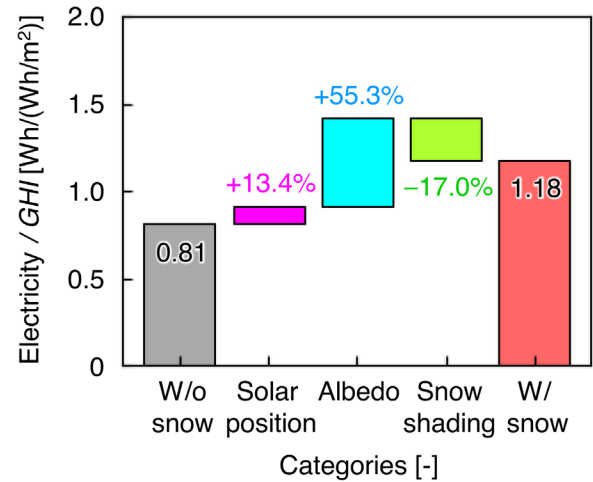


Fig. 5. Impact of snow on power generation of vertical bifacial PV system.

accumulated power generation normalized by GHI was 0.81 Wh/(Wh/m²). However, this value rose to 1.18 Wh/(Wh/m²) during snowy periods, reflecting an increase in output of approximately 1.46 times compared to snow-free periods. This increase results from a combination of factors including the high albedo of snow, enhanced irradiation on vertical surfaces due to seasonal variations in solar position, and partial shading by snow accumulation.

The impact of these factors is further illustrated in Figure 5, which presents a waterfall chart analyzing the contributions to the ratio of electricity to GHI due to snow. The gray and red bars represent the measured average daily accumulated electricity/GHI for periods without and with snow, respectively, throughout the year. The pink bar indicates the increment due to variations in the solar position between snow-covered and snow-free periods, calculated from the measured GHI. The Perez model [25]

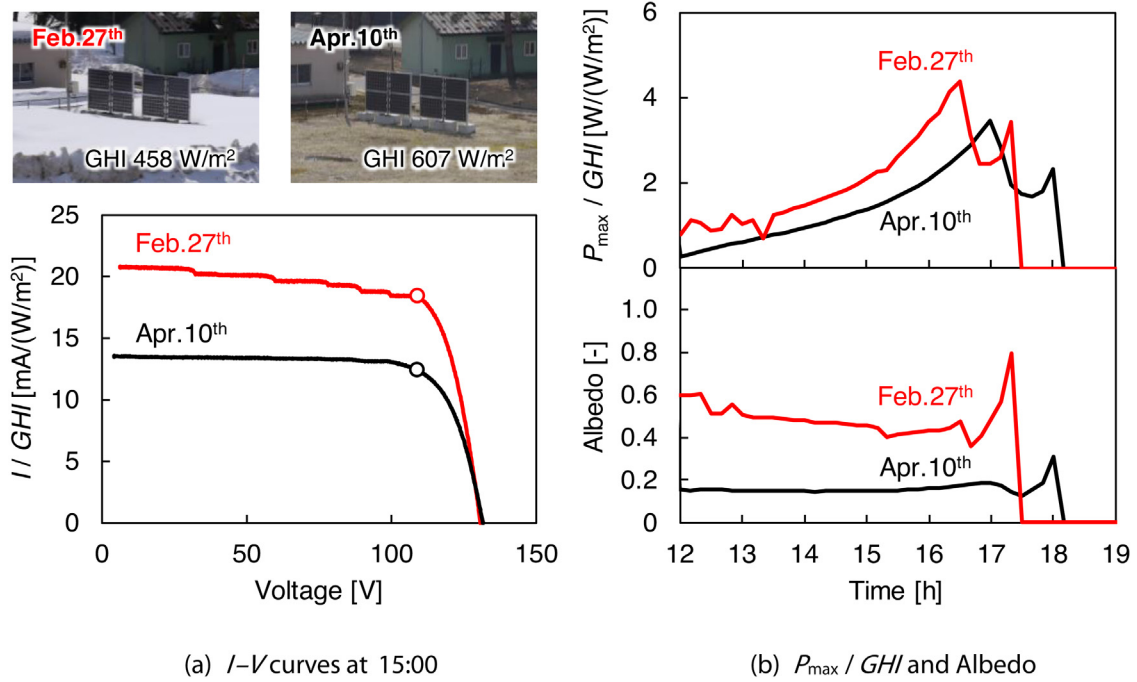


Fig. 6. (a) I - V characteristic and (b) variation of $P_{\max}/GHI$ of bifacial PV and albedo in the afternoon of Feb. 27 (w/ snow) and Apr. 10 (w/o snow).

was employed to convert the measured GHI to the irradiance on the vertical surfaces. The light blue bar shows the increase due to the enhanced albedo from snow, which was estimated from the measured E_{POA} . Here, E_{POA} is defined as $E_{POA} = E_{\text{front}} + \phi E_{\text{rear}}$, where E_{front} and E_{rear} represent the irradiance on the west-facing and east-facing vertical surfaces, respectively, and ϕ denotes the bifaciality factor (0.8). Since the measured E_{POA} includes gains from both snow albedo and changes in solar position, the gain attributable solely to changes in solar position was subtracted. The yellow-green bar represents the loss due to partial shading by snow, calculated as the difference between the estimated power generation with both increments and the actual measured power generation. The contribution from snow albedo leads to a 55.3% improvement, whereas partial shading by snow results in a 17.0% reduction. Consequently, the net improvement attributable to snow amounts to 38.3%. Moreover, the vertical bifacial PV systems showed no signs of breakage or apparent damage, such as deformation of the module frame or breakage of the glass cover, even after withstanding two winter seasons of snow accumulation.

Figure 6a depicts the I - V characteristics at 15:00 on February 27, 2023, with a snow accumulation ($H_s = 0.35$ m), compared to those on April 10, 2023, a day with no snow. On the February date, the snow depth was below the lower edge of the array. Due to partial shading from an adjacent building in the morning, variations were excluded as they rendered the comparison inappropriate. Figure 6b displays the changes in $P_{\max}$ and albedo during the afternoon of the same day. To facilitate comparison, the current and $P_{\max}$ values were normalized by the GHI

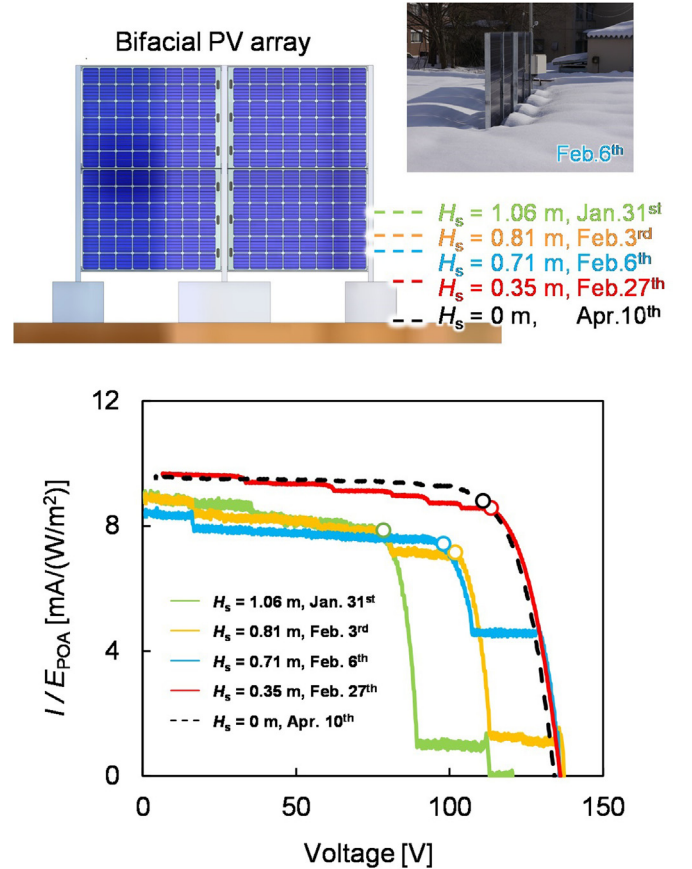


Fig. 7. Measured I - V curves at 15:00 for various snow depths.

Table 2. Measurements for various snow depths corresponding to Figure 7.

Date	H_s [m]	V_{mp} [V]	I_{mp} / E_{POA} [mA/(W/m ²)]	Fill factor [–]	P_{max} / E_{POA} [W/(W/m ²)]
Jan. 31st	1.06	78.4	7.9	0.591	0.62 (–36.8%)
Feb. 3rd	0.81	101.8	7.2	0.589	0.73 (–25.3%)
Feb. 6th	0.71	98.0	7.4	0.648	0.73 (–25.3%)
Feb. 27th	0.35	113.5	8.6	0.740	0.97 (–0.3%)
Apr. 10th	0 (w/o snow)	110.9	8.8	0.760	0.98 (0)

to account for the different solar irradiance levels on the two days. Blank circles in Figure 6a indicate points of maximum power, P_{max} . On February 27, the normalized current exceeded that on April 10 across the entire voltage range, with the normalized I_{sc} being approximately 1.5 times higher than that observed without snow. While seasonal variations in the solar path may contribute to this difference, the increase in current was primarily attributed to the irradiance reflected by the snow surface (Fig. 6b), where the average albedo from noon to sunset on February 27 was approximately 3.1 times greater than on April 10. However, under snowy conditions, the normalized current exhibited a gradual step-like decrease in the 0–100 V range (Fig. 6a), indicating a non-uniform distribution of irradiance on the modules, likely caused by reflection from the snow surface. Additionally, Figure 6b illustrates that the normalized P_{max} was consistently higher on snowy days compared to snow-free days. From noon to sunset, normalized P_{max} averaged 1.6 times higher on snowy days than on days without snow. Figure 7 displays the experimental results of I – V characteristics under varying snow depths. The data are represented by different colors: green for January 31, yellow for February 3, blue for February 6, red for February 27, and black for April 10, all recorded at 15:00. Blank circles denote the points of P_{max} for each condition. The snow depths (H_s) are as follows: 1.06 m on January 31, 0.81 m on February 3, 0.71 m on February 6, 0.35 m on February 27, and 0 m (no snow) on April 10. For comparative purposes, current values were normalized by the E_{POA} , calculated from measurements on both the front and rear sides of the array. Table 2 summarizes the measurements, including H_s , V_{mp} , fill factor, and normalized I_{mp} and P_{max} . The I – V curve in Figure 7 appeared smooth for solar cells not covered by snow, specifically when H_s was less than 0.50 m. However, for H_s greater than 0.50 m, discrepancies in current emerged between snow-covered and uncovered sections of the module, activating BPD and resulting in step-like alterations in the I – V curve. For H_s of 0.71 m and 0.81 m, a step-like reduction in current was observed due to snow cover on the bottom two rows of solar cells. At an H_s of 1.06 m, a significant step-like decrease in current occurred as four rows of solar cells were covered by snow. These step-like changes reduced the current at I_{mp} , consequently lowering P_{max} . As a result, normalized P_{max} values decreased by 37%, 25%, and 25% for H_s of 1.06 m, 0.81 m, and 0.71 m, respectively, due to partial shading from snow. The subsequent section will explore whether these experimental results can be replicated through simulations.

4 Simulation results

4.1 Validation of simulation

Figure 8 compares the measurement and simulation results of the I – V curves at various snow depths, corresponding to those shown in Figure 7. The solid lines represent experimental results, while the dashed lines denote simulated outcomes. Circular and diamond markers denote the points of P_{max} for measured and simulated values, respectively. The deviations of I_{sc} and V_{oc} between simulated and measured values ranged from 1% to 22%. These discrepancies arise from inaccuracies in estimating direct and diffuse irradiance using the Erbs model, and the assumption of a constant cell temperature in the simulation. The irradiance distribution across the PV array under each condition is illustrated in the accompanying graphs. Here, cell irradiance is computed as the sum of rear-side irradiance multiplied by a factor φ and front-side irradiance. The graphs clearly illustrate reduced cell irradiance due to partial shading from snow accumulation at the lower part of the array. Larger H_s values correspond to a broader range of cells experiencing reduced irradiance. Additionally, the simulation successfully replicates the step-like decrease in current caused by partial shading. Discrepancies between measurements and simulations at $H_s = 1.06$ m and 0.81 m may be attributed to assumptions regarding the constant gap between the snow and the module. In actual conditions with $H_s = 1.06$ m, where fresh snow remained in close contact with the module surface, the analysis assuming a 10 cm gap led to an overestimation because of greater light penetration into the cells than in reality. Conversely, with $H_s = 0.81$ m, the gap between snow and the module exceeded 10 cm, allowing more light to penetrate the cells, resulting in underestimation. Despite these variances, the analytical approach demonstrates good reproducibility overall, validating the proposed simulation methodology.

4.2 Mitigation of decrease in power generation due to snow shading

When the snow depth exceeded the bottom of the PV array, partial shading caused a distinct step in the I – V curve, resulting in decreased power generation. The PV array in our experiment comprised a single string of four connected PV modules in series, referred to as the 1-string configuration. Simulation results indicated that snow accumulation significantly reduced irradiance on cells in the lower module, exacerbating the distortion in the array's

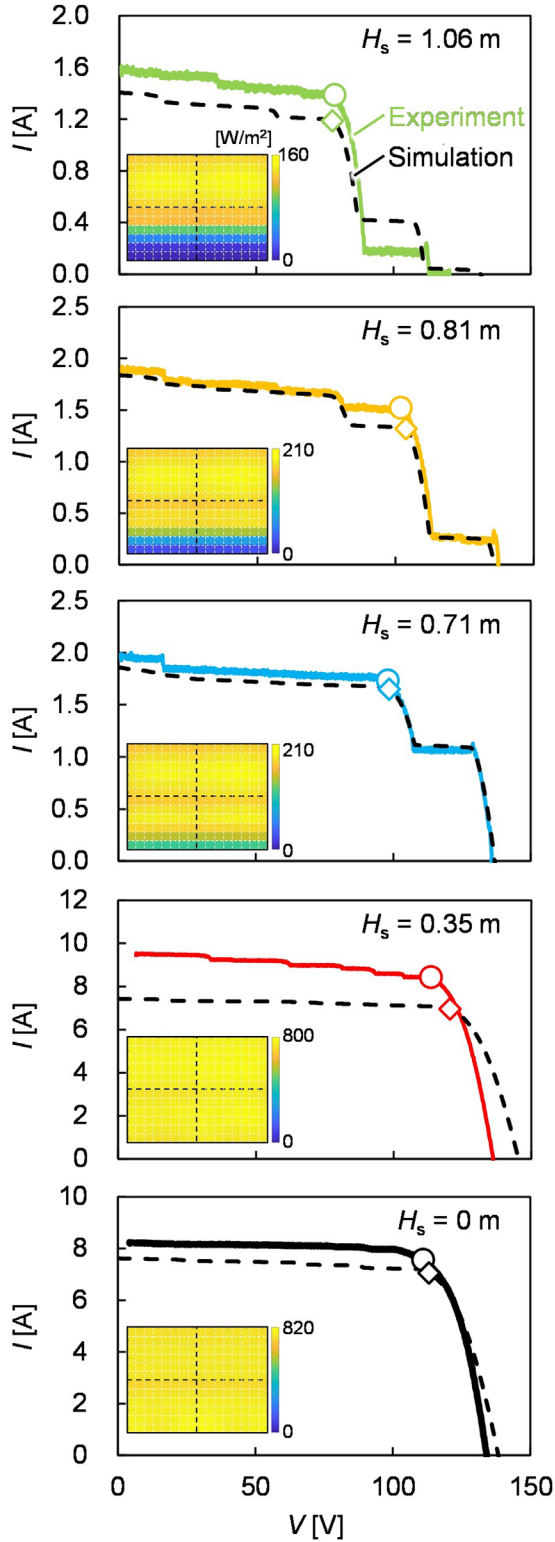


Fig. 8. Simulated I - V curves for bifacial PV at snow depth values corresponding to Figure 7.

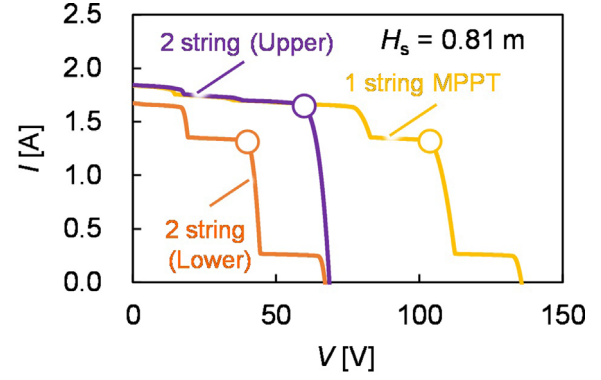


Fig. 9. Simulated I - V curve of bifacial PV with different module connections: 1-string configuration (four modules are connected in series and maximum power point tracking (MPPT) is applied), 2-string configuration (two upper modules are connected in series, and two lower modules are connected in series, and MPPT is independently applied to each string).

I - V curve. To mitigate the power loss due to snow shading, we explored the effectiveness of separating the upper and lower modules into two strings (2-string configuration) and applying independent maximum power point tracking (MPPT) to each string.

Figure 9 illustrates simulated I - V curves for $H_s = 0.81$ m in both the 1-string and 2-string configurations. The yellow, orange, and purple lines represent the I - V characteristics of the 1-string configuration, the lower string, and the upper string in the 2-string configuration, respectively. Blank circles indicate the maximum power points. It is evident that $P_{\max}$ for the arrays in the 1-string and 2-string configurations were 136.8 W and 145.6 W, respectively, resulting in a 6.4% increase in $P_{\max}$ due to string separation. In the 1-string configuration, the step in the I - V curve of the lower string led to a decrease in I_{mp} , consequently reducing $P_{\max}$. Therefore, string separation proves more effective in mitigating power loss when there is a substantial decrease in I_{mp} caused by snow shading.

The upper graph in Figure 10 presents a box plot of the simulated improvement ratio in power generation for the 2-string configuration compared to the 1-string configuration across various H_s values. This improvement ratio was predicted using simulations based on measurement results. The lower graph in Figure 10 displays the measured total power generation for the 1-string configuration corresponding to each H_s . As H_s increased, the improvement ratio in power generation became more pronounced, particularly when cells were covered by snow ($H_s > 0.50$ m). At $H_s = 1.2$ m, the average improvement ratio was 25.3%. The overall improvement ratio for total power generation during the snow season was 4.3%, corresponding to approximately 0.6% of total power generation over the entire period, encompassing all seasons.

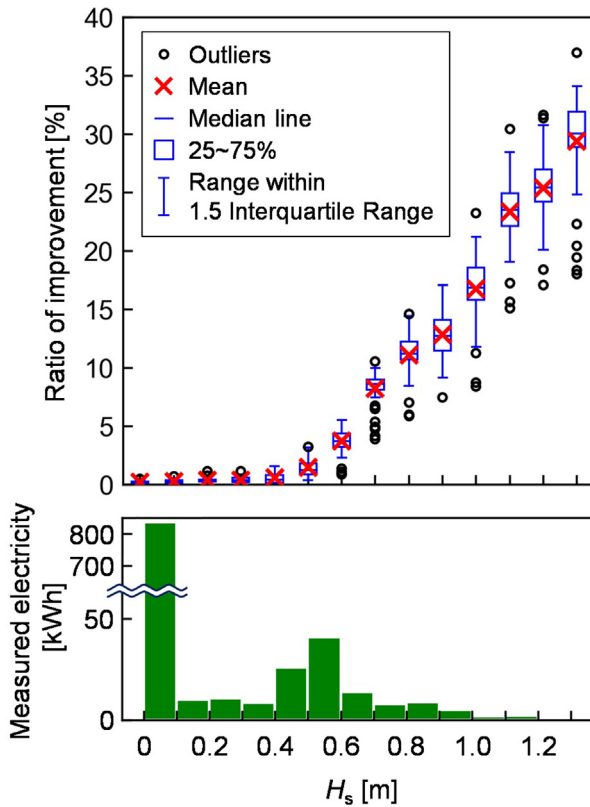


Fig. 10. Ratio of improvement and measured electricity for varying snow depths. The ratio of improvement denotes the change in $P_{\max}$ of the array with a 2-string configuration with respect to that of the array with a 1-string configuration. The measured electricity corresponds to the experimental results from the array with 1-string configuration.

5 Conclusion

This study conducted experiments and simulations to examine the impact of snow on the power-generation characteristics of vertical bifacial PV systems, which are suitable for regions with heavy snowfall. After exposure to two winter seasons with snow depths exceeding 1 m, no significant failures, such as deformation of PV module frames or breakage of glass covers, were observed, suggesting the durability of vertical bifacial PV systems in challenging environments. However, long-term testing is necessary to confirm these observations. Additionally, power generation relative to the plane of array irradiance increased by approximately 55% due to irradiance reflected from the snow surface. However, shading of solar cells by snow resulted in a step-like current profile in the I - V curves, leading to a 17% decrease in power output during the snow season. An integrated analytical approach, combining optical simulation and electrical circuit models, was used to verify the reduction in power generation due to snow shading and to explore mitigation strategies, such as separating the upper and lower strings of the vertical bifacial PV for independent MPPT. As a result, total power generation during the snow season increased by approximately 4.3%. The estimated enhancement in overall power

generation for the entire measurement period (May 1, 2022, to April 30, 2023) attributable to string separation was approximately 0.6%. These findings underscore the efficacy of string separation in mitigating power generation declines caused by snow accumulation in vertical bifacial PV systems. The effectiveness of string separation is expected to be more pronounced in regions with higher irradiance during snowfall. While the PV array in this study was arranged in a single row, adjacent arrays may introduce shading effects on lower modules depending on array pitch, potentially enhancing the benefits of string separation. Additionally, adjacent arrays may alter the amount of reflected light from the snow surface incident on vertical modules due to shadows cast on the snow by neighboring PV arrays, a phenomenon that requires further investigation. Future research should involve validation using larger multi-row arrays to examine the impacts of snow and shading from adjacent arrays on power generation. Despite these considerations, the insights gained from this study help us understand the impact of snow on the power generation of vertical bifacial PV systems in heavy-snow regions, thereby contributing to more efficient system designs.

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Conflicts of interest

The authors have nothing to disclose.

Data availability statement

All data and material are available upon reasonable request.

Author contribution statement

Conceptualization, T.O. and N.Y.; Methodology, Y.T. and N.Y.; Software, S.T. and Y.T. and D.S.; Validation, S.T. and Y.T. Y.Y. and Z.Z.; Formal Analysis, S.T.; Investigation, S.T. and Y.T.; Resources, Y.T. and T.O. and N.Y.; Data Curation, S.T. and Y.T.; Writing – Original Draft Preparation, S.T. and N.Y.; Writing – Review & Editing, Y.T.; Visualization, Y.T.; Supervision, N.Y.; Project Administration, N.Y.; Funding Acquisition, T.O. and N.Y.

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